S. Hrg. 102-5 (Pt. 16)

NATIONAL ENERGY SECURITY ACT OF 1991

(Appendixes to Parts 8, 9, 10, 11, 12 and 13)

HEARINGS

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED SECOND CONGRESS

FIRST SESSION

ON

Appendixes to S. 341

PERTAINING TO

Part 8

TITLE IX (MAR. 12)

Part 9

TITLE XV (MAR. 14)

Part 10

SECTION 5101 OF TITLE V (MAR. 18)

Part 11

SUBTITLE A OF TITLE V (MAR. 19)

Part 12

SUBTITLE A OF TITLE III (MAR. 19)

Part 13

SUBTITLE A OF TITLE IV (MAR. 21)

PART 16

Printed for the use of the
Committee on Energy and Natural Resources

U.S. GOVERNMENT PRINTING OFFICE
43-270 ⇆ WASHINGTON : 1991

S311-56

For sale by the Superintendent of Documents, Congressional Sales Office
U.S. Government Printing Office, Washington, DC 20402

COMMITTEE ON ENERGY AND NATURAL RESOURCES

J. BENNETT JOHNSTON, Louisiana, *Chairman*

DALE BUMPERS, Arkansas
WENDELL H. FORD, Kentucky
BILL BRADLEY, New Jersey
JEFF BINGAMAN, New Mexico
TIMOTHY E. WIRTH, Colorado
KENT CONRAD, North Dakota
DANIEL K. AKAKA, Hawaii
WYCHE FOWLER, Jr., Georgia
RICHARD C. SHELBY, Alabama
PAUL WELLSTONE, Minnesota

MALCOLM WALLOP, Wyoming
MARK O. HATFIELD, Oregon
PETE V. DOMENICI, New Mexico
FRANK H. MURKOWSKI, Alaska
DON NICKLES, Oklahoma
CONRAD BURNS, Montana
LARRY E. CRAIG, Idaho
JOHN SEYMOUR, California
JAKE GARN, Utah

Benjamin S. Cooper, *Staff Director*
D. Michael Harvey, *Chief Counsel*
G. Robert Wallace, *Staff Director for the Minority*
Gary G. Ellsworth, *Chief Counsel for the Minority*

CONTENTS

MARCH 12, 1991

(Title IX)

Page
Appendix I—Responses to additional questions from:
    James D. Watkins, Secretary, Department of Energy 1
    David C. O'Neal, Department of the Interior 9
    J.D. Hull, Captain, U.S. Coast Guard, Department of Transportation 24
    James B. Hermiller, Alyeska Pipeline Service Co 26
    Roger C. Herrera, BP Exploration (Alaska), Inc. 63
Appendix II—Additional material submitted for the record 68

MARCH 14, 1991

(Title XV)

Appendix I—Responses to additional questions from:
    Edward H. Fleischman, Securities and Exchange Commission 185
    Linda G. Stuntz, Department of Energy 195
    Cynthia A. Marlette, Federal Energy Regulatory Commission 220
    Scott Hempling, Environmental Action Foundation 231
    Don D. Jordan, Houston Lighting & Power Co 238
    R.J. Snokhous, Houston Lighting & Power Co 244
    Joseph I. Giarrusso, City Council of New Orleans 255
    Patricia M. Eckert, Public Utilities Commission of California 260
    Charles A. Patrizia, Offices of Paul, Hastings, Janofsky & Walker 263
Appendix II—Additional material submitted for the record 271

MARCH 18, 1991

(Section 5101 of Title V)

Appendix I—Responses to additional questions from:
    David G. Hawkins, Natural Resources Defense Council 375
    Anthony J. Ahern, American Electric Power Serevice Corp 377
Appendix II—Additional material submitted for the record 414

MARCH 19, 1991

(Subtitle A of Title V)

Appendix I—Responses to additional questions from:
    Robert Gentile, Department of Energy 423
    William Carr, National Coal Council, Inc 506
    Kurt E. Yeager, Electric Power Research Institute 580
    Paul G. LaHaye, Hague International 587
Appendix II—Additional material submitted for the record 592

MARCH 19, 1991

(Subtitle A of Title III)

Appendix I—Responses to additional questions from:
    B. Reid Detchon, Department of Energy 603
Appendix II—Additional material submitted for the record 635

MARCH 21, 1991

(Subtitle A of Title IV)

	Page
Appendix I—Responses to additional questions from:	
George E. Helland, Jr., Department of Energy	645
Appendix II—Additional material submitted for the record	652

APPENDIXES TO MARCH 12, 1991 HEARING

(Title IX)

Appendix I—Responses to Additional Questions

Department of Energy
Washington, DC 20585
April 10, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

On March 25, 1991, I sent you the edited transcript of testimony given on March 12, 1991 by James D. Watkins, Secretary of Energy.

The information you requested, transcript page 103, was still being prepared at the time. The information has been compiled and is enclosed for the record.

If we can be of further assistance to you or your staff, please contact our Congressional Hearing Coordinator, Barbara Barnes, on (202) 586-6341.

Sincerely,

Jacqueline Knox Brown

Jacqueline Knox Brown
Assistant Secretary
Congressional and Intergovernmental
Affairs

Enclosure

You ask about what would the effect be of taxing and giving the money back. We have studied that. Our economists have. We are more than happy to share it with your staff.

If you tax them and give the money back, over a 20-year period, our figures are a $570 billion loss in present value to the economy. It does not work dollar for dollar.

Senator Bradley: What is the tax?

Mr. Moore: Whatever tax level you want to put it at. I can give you a level we did. $1 a gallon is the one we looked at; 67 cents would not cut that figure too far down from $1. And if you would like to have your staff look at that analysis, I would be glad to show it to them.

Senator Bradley: Elasticities are always a very interesting subject to pursue.

Mr. Moore: Taxing never helps an economy, Senator.

Senator Bradley: So we will take a look at whatever you provide us, as opposed to simply taking your statement -- because you have made it -- as valid.

[The information referred to follows:]

[COMMITTEE INSERT]

Macroeconomic and Federal Budget Effects of a Phased $1.00 Gasoline Tax

The macroeconomic losses and Federal budget effects presented in this report are based on simulations of the Data Resources, Inc. U.S. Quarterly Model. Forecast values for energy price and quantities are extracted from the Energy Information Administration Transportation Energy Demand Model and inserted into the DRI model to derive alternative macroeconomic cases.

The simulations were carried out in two modes. In the Deficit Reduction mode, the gross collections from the imposition of the tax raise Federal indirect business tax revenues and these additional revenues are assumed to be used to reduce the deficit. In the Deficit Neutrality mode, the gross revenues are not used to reduce the Federal deficit. The simulation explicitly targets the "full employment Federal deficit" to remain at baseline throughout the forecast period. Two mechanisms for targeting the deficit neutrality are investigated - a payroll tax cut and a reduction in the effective personal income tax rate. The Economic Policy Council on Energy Taxes advocates the deficit neutral approach for the assessment of energy tax policy options. There is no accommodating monetary policy accompanying the imposition of the taxes.

The table below highlights the net present value effects of the alternative taxes on Real GNP and Potential GNP (the output of the economy at full employment of resources).

ECONOMIC IMPACTS OF THE IMPOSITION OF A
PHASED $1.00 GASOLINE TAX

Increments of 25 Cents per Year 1992 to 1995,
Constant in Real Terms from 1995 Through 2020

	Net Present Value of Real and Potential GNP Loss					
	Real GNP			Potential GNP		
	1992-2000	1992-2010	1992-2020	1992-2000	1992-2010	1992-2020
Deficit Reduction	-353	-473	-379	-51	-132	-93
Deficit Neutrality						
Personal Tax Cut	-273	-539	-571	-69	-265	-322
Payroll Tax Cut	-133	-328	-384	-39	-178	-237

The Deficit Reduction Case

The imposition of a gasoline tax would have a direct impact on consumer spending and on the aggregate price level of the economy, with a complex time-profile of impacts on aggregate output. From the point of view of the consumer, two issues prevail. First, households will be faced with higher prices for gasoline and will adjust their driving habits, generally cutting back on the amount of gasoline consumed. Nonetheless, nominal expenditures will likely rise, taking a larger share of the family budget. Consumers can be expected to reduce their expenditures on other goods and services. Second, as suppliers of labor, the tax increase effectively reduces real disposable income. Higher wage demands to offset the income loss represent a cost increase in the production of all goods and services.

Gasoline, primarily in the form of transportation services, is also used as an input in the production of goods and services. After energy prices increase, substitution away from energy is limited and the prices of other inputs do not fall. This raises the production costs per unit of output for firms. Higher wage costs and spillover price effects on other variable costs further escalate production costs throughout the economy. This process places upward pressure on the nominal prices of all intermediate goods and final goods and services in the economy.

In the long-run, higher energy costs would reduce the use of energy by shifting production toward less energy-intensive sectors, by replacing energy with labor and capital in specific production processes, and by encouraging energy conservation. Although reflecting a more efficient use of higher-cost energy, this gradual reduction in energy use would tend to lower the productivity of other factors in the production process. Depending principally on the long-range effects on investment behavior, the economy will rebound back toward the baseline path, and may even oscillate around the baseline path.

The effect on interest rates is subject to uncertainty, depending on the reaction of the monetary authorities. Lowering Federal government borrowing will place downward pressure on interest rates. However, if there is no change in the level of non-borrowed reserves, the higher aggregate price level effectively reduces the real supply of money. This will place significant upward pressure on interest rates.

On balance, the effect of the higher price level in the economy should dominate in the near-term forcing both nominal and real interest rates above baseline. The rise in interest rates discourages investment and interest-sensitive components of consumer expenditures such as automobiles, housing and other durable purchases. In the long-term, as price inflation in the economy abates, the continuing reduction in Federal government borrowing serves to ultimately lower interest rates relative to the baseline.

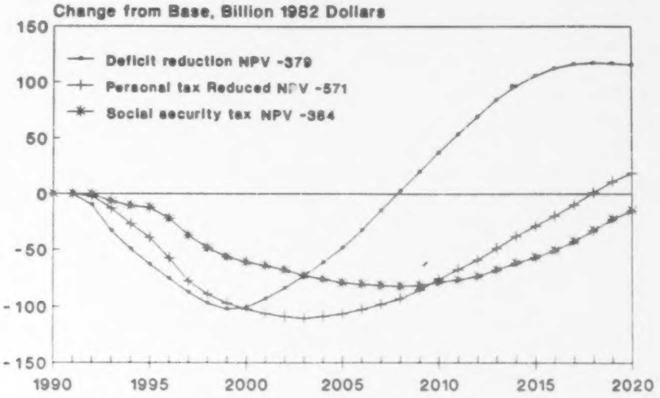
The imposition of a gasoline tax collects an *ex-ante* level of revenues which is assumed to reduce the Federal deficit. However, with feedback effects on the economy considered, *ex-post* collections fall short of planned through the year 2000. By 2010, with the economy back to baseline activity, the reduction in the deficit matches collections. The rapid decline in the level of the Federal debt, coupled with a fall in interest rates and interest payments on the debt actually serve to reduce the deficit by more than collections in the post-2000 period.

The Deficit Neutrality Case

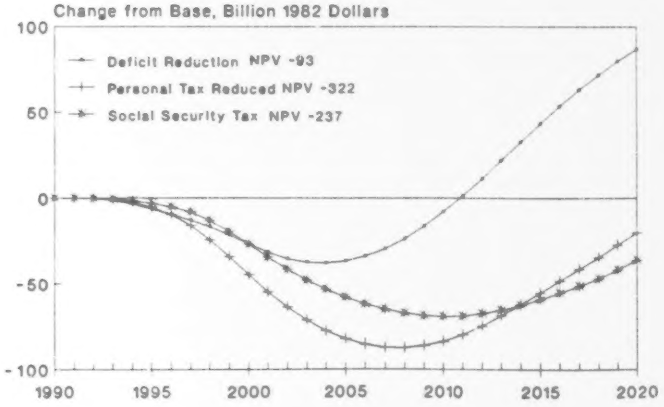
The pattern of collections relative to reductions in the Federal deficit is important to consider in defining a deficit neutrality case. In essence, "deficit neutrality" is not "fiscal neutrality". In order to achieve deficit neutrality through 2010, less is returned to consumers or business than is actually collected. This is because the reduction in the deficit in the case discussed above was less than collections. In the post 2010 period, more is returned than collected. In this way, the federal deficit is maintained essentially at baseline levels.

As Figure 1 indicates, the return of collected tax revenues to consumers and business has the effect of moderating the GNP losses through the year 2000. The personal tax cut reduces the net present value of the Real GNP loss to $273 billion from the loss of $353 billion in the deficit reduction case. The personal tax cut spurs consumption by increasing disposable income, but does nothing to lessen the underlying inflationary pressures set in place by the gasoline tax. The payroll tax, by cutting business costs, helps to control inflation. As a result, it is even more effective, lowering the loss to $133 billion.

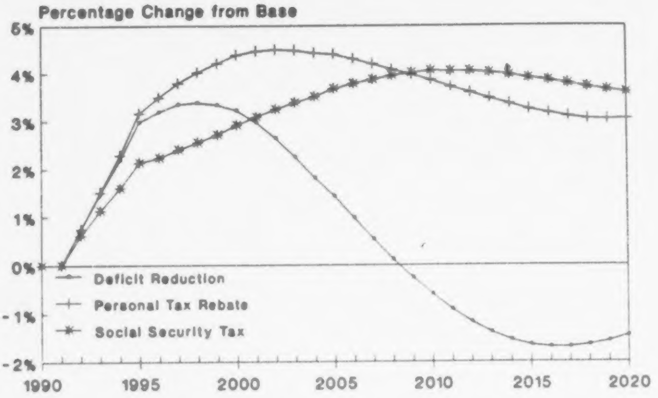
However, if a longer time horizon is considered, the effectiveness of the deficit neutrality cases changes appreciable relative to the deficit reduction case. The personal income tax cut case actually yields higher GNP losses than the deficit reduction case when measured alternatively from 1990 through 2010 and through 2020. The aggregate price level remains above baseline. The improvement to consumption experienced in the first 10 years begins to wane. Worse, investment activity remains weak, particularly with interest rates remaining above baseline. The payroll tax cut yields the smoothest transition. Measured over the entire 30-year period, this case yields almost an almost identical GNP loss ($384 billion) to the deficit reduction case ($379 billion).



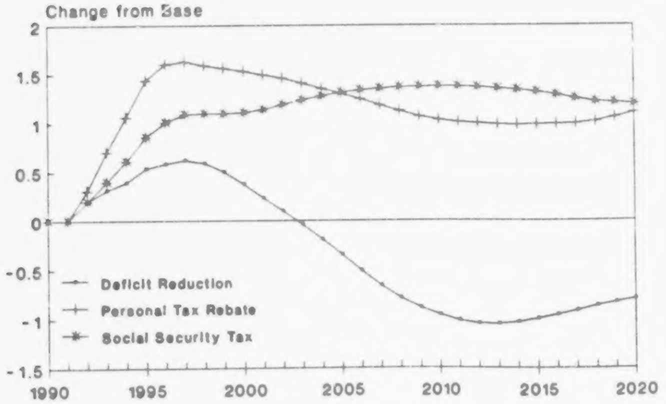
Phased Gas Tax 25c To $1.00
Real GNP



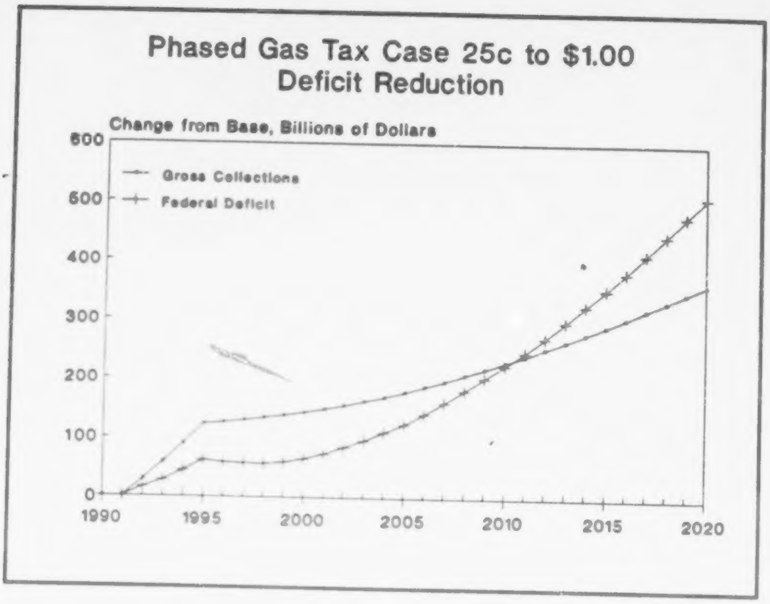
Phased Gas Tax-25c to $1.00
Potential GNP



Phased Gas Tax 25c to $1.00
Consumer Prices



Phased Gas Tax 25c to $1.00
3 Month Treasury Bill



Phased Gas Tax Case 25c to $1.00
Deficit Reduction

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

APR 4 1991

Honorable J. Bennett Johnston
Chairman, Committee on Energy
and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

In response to your letter of March 19, 1991, I am pleased to provide answers to questions raised by Senators Wallop and Murkowski for inclusion in the Hearing Record of the March 12, 1991, Committee hearing on Title IX of S. 341, to authorize a competitive oil and gas leasing program for the Coastal Plain of the Arctic National Wildlife Refuge in Alaska.

Sincerely,

James M Hughes
for David C. O'Neal
Assistant Secretary, Land and
Minerals Management

Enclosure

1. **The current legislation demands a sealed bid process, as opposed to the normal process which has usually been oral bids, so I am told. Would the process benefit from oral bids, and if so, please explain.**

The Oil and Gas Leasing Reform Act of 1987 required all Federal oil and gas leasing within the lower 48 States to be conducted using oral bidding. However, the Act also did away with the requirement that the Government perform a formal economic evaluation to ensure the receipt of fair market value. Instead, the Government relies on competition in the market to ensure the receipt of fair market value for the lease tracts. This approach seems to be very appropriate for the relatively low valued tracts offered for lease in the lower 48 States.

In ANWR, we anticipate the tracts offered for lease will be considered by industry as high potential, high value tracts. As such, we feel a better analogy is the Outer Continental Shelf (OCS) lease sale bid process. Generally, OCS tracts are considered by industry as high potential, high value tracts. The Department has very successfully employed a sealed bidding process in the leasing of OCS tracts. Sealed bids for high value tracts, coupled with the Federal Government's estimate of fair market value to screen against low or non-serious bids, has led to an efficient and cost effective system. We see no reason to adopt a possibly expensive and time-consuming oral bidding process in light of the success we have experienced in OCS leasing.

2. There have been accusations in the press that ANWR has only a 200-day supply and will only supply 2% of our oil needs. Can you put this into some kind of perspective, so that my constituents can understand what a 200-day supply actually means?

The 200-day supply figure assumes all domestic oil consumption will be met from ANWR. This, of course, is impossible. It has been estimated that it will take 30 years to fully develop and produce the expected oil finds within ANWR. We feel production from ANWR will represent eight to ten percent of our domestic production over the 30-year period based on our mean estimate of recoverable reserves. The oil reserves could be as large or larger than those found in Prudhoe Bay. In 1990, Prudhoe Bay met approximately one quarter of our domestic production. In a time when both domestic and Prudhoe Bay production are declining, the estimated ANWR production is substantial and will provide large economic benefits to the United States.

3. What amount of proven reserves on the North Slope will be foregone due to pipeline capacity if there is no development at ANWR? Have those amounts been factored into the potential of ANWR?

   According to recently released DOE study, if no new large fields are developed on the North Slope, TAPS could shut down by the year 2009. By that time, oil production would have declined to approximately 300,000 barrels per day. At this throughput rate, production may not be economically or mechanically feasible, resulting in the shutdown of the pipeline.

Once the pipeline is shut down, the feasibility of reopening the pipeline is in serious doubt. We therefore risk the recovery of possible new reserves from ANWR in addition to leaving approximately 1 billion barrels of reserves from currently producing fields in the ground without any means to deliver the oil to market.

4. If Congress does not authorize the opening of the ANWR Coastal Plain, what is the next best new domestic source of crude oil?

The only other domestic area that has the potential for the discovery of oil resources in the magnitude that is anticipated in ANWR is the Outer Continental Shelf (OCS).

5. Why should we make a decision on whether or not to open the Coastal Plain to oil and gas development when the world will probably experience an oil glut as Iraq and Kuwait resume production?

The potential oil glut that may occur with the resumption of oil production from Iraq and Kuwait will be a short-term phenomena. After 1995 -- 2000, forecasters are projecting rising real oil prices and tighter world oil markets. The potential oil production that may come from ANWR is not expected until the next century. With leasing in the mid-1990's and a significant discovery by the end of the century, peak production from ANWR will still not occur until 2005 or later. We view the current time period as our window of opportunity to bring ANWR production on-line before events (i.e. the shut-down of TAPS) make such an option unrealistic.

The underlying problem is that domestic and North Slope oil production is declining dramatically. In 1989, domestic production was 7.7 MMBPD, in 1990 it was 7.3 MMBPD, and by the year 2010 it is estimated domestic production will be between 4.1 to 5.6 MMBPD. In that same time period, Alaska production, primarily due to a rapid decline in Prudhoe Bay production, will decline from 25 percent of total domestic production to about 10 percent of the total. Over the next five years, North Slope production is expected to decline at a rate approaching 10 percent per year.

Meanwhile, imported oil will increase from 42 percent of total oil consumed in 1989 to about 67 percent by 2010. Given past disruptions to our foreign oil sources, including the recent Gulf crisis, it seems unwise to rely on such a tenuous source. Maintaining our domestic supply of oil is sound planning given the importance of oil to our economy and national security, not to mention the impact on our national trade situation.

6. Should Congress mandate the use of the best commercially available technology for oil production from ANWR or do you believe that market pressures will be more effective?

We believe the market dictates the application of the most appropriate technology in a much more effective and efficient manner than can be prescribed by the Government. The situation may exist where the best

available may not be the most appropriate technology to apply. Industry has demonstrated in the past the ability and flexibility to apply the most appropriate technology in an efficient and effective manner to meet certain prescribed standards of performance. We believe this should be the case for oil and gas exploration, development, production, and reclamation activities within ANWR, where a key part of those standards will focus on maintaining environmental quality and fish and wildlife and habitat resources of the area.

7. Why should we open the Coastal Plain to oil and gas operations when we can increase the mileage of our automobiles and save more oil than can be produced from the Coastal Plain?

The assumptions utilized to arrive at the total savings due to a prescribed change in the mileage for automobiles are somewhat questionable. The economic costs of such oil savings can be very high, amounting to several times the price per barrel of oil. In addition, such an approach may increase safety risks that are also costly. However, the answer to meeting our Nation's energy needs is not in an either/or solution. Both conservation and new production, plus the development of alternative energy sources, are critical to meet the Nation's energy needs. No one solution can realistically address the energy problem this Nation is and will be facing. One critical component is the continued production of oil from domestic sources. ANWR oil production would be economic at projected oil prices. Without any significant increases in the supply of domestic oil, imports could account for 67 percent of our Nation's oil consumption by the year 2010.

8. If ANWR oil is valued at $15 per barrel, what is the value to this nation of production from the Coastal Plain of 500,000, 750,000 or 1 million barrels per day?

Assuming a 16 2/3 percent royalty on the value of the product, the royalty would be:

Barrels/Day	Product Value in Millions	Royalties/Day in Millions	Royalties/Year in Millions
500,000	$7.50	$1.250	$456.250
750,000	$11.25	$1.875	$684.376
1,000,000	$15.00	$2.500	$912.502

The Federal share of that royalty depends on whatever percent is finally determined by law. There would obviously be many other gains to the Nation, including tax, rental and bonus revenues, job gains, and decreased importation of oil, increasing our national security and improving our balance of trade.

Overview Of The 1991 Arctic National Wildlife Refuge Recoverable Petroleum Resource Update

Bureau of Land Management

Department of the Interior

April 8, 1991

April 8, 1991

Overview of the 1991 Arctic National Wildlife Refuge Recoverable Petroleum Resource Update

Summary of Findings

The 1991 update of recoverable petroleum resources in the 1987 Arctic National Wildlife Refuge, Alaska, Coastal Plain Assessment, also known as the 1002 Report, makes a considerable contribution to the knowledge and understanding of the petroleum geology of the 1002 area of the Arctic National Wildlife Refuge (ANWR). This study reaffirms most of the conclusions and estimates made in the 1002 Report, and increases the level of confidence that ANWR is part of the North Slope oil province. This is demonstrated by the increase in the marginal probability of economic success from 19 percent in the original assessment to 46 percent in the current assessment. The increase in marginal probability means that ANWR has a higher potential for oil discovery. The overall Minimum Economic Field Size (MEFS) for the 1002 area has been lowered from about 0.44 billion barrels of oil (BBO) to about 0.40 BBO. The mean resource estimate has increased from 3.23 to 3.57 BBO.

Introduction

The original recoverable resource assessment was included in the 1002 Report, published in 1987. It was well received in reviews of the report by industry and the scientific community, but, as was its intent at that time, was considered conservative. The intent of Section 1002(h) of ANILCA was to give the Secretary of the Interior sufficient information to make an informed decision for his recommendation to Congress pertaining to oil and gas leasing in the 1002 area. The 1991 assessment was prepared as a part of routine updating of resource assessments that takes place every 2 to 5 years and that reflects new and reinterpreted geological data, state-of-the-art engineering, current tax provisions, and updated economic data.

Because Congress intended for the 1987 assessment to be conducted with as little impact on the 1002 area as possible, they did not authorize the drilling of test wells. Therefore, the only sources of information available for the 1002 study were records from wells drilled in the surrounding area and about 1,300 line miles of seismic reflection data shot by a consortium of 25 companies on an approximate three-by-six mile grid in the 1002 area. Selected gravity readings collected by industry from the 1002 area and the results of surface geologic work conducted by in-house and various outside sources in and around the coastal plain were also available and beneficial to the study. With this amount of information and given the timeframe for completion of the study, a conservative approach was taken in order not to overestimate the economically recoverable hydrocarbon potential in the area.

Since the 1002 Report was completed in 1987, the BLM in Alaska has obtained access to information from four wells drilled near or adjacent to ANWR. They are Tenneco's Aurora No. 1, Unocal's Hammerhead No. 1, and Shells' Corona No. 1, all located offshore from ANWR, and Unocal's Leffingwell No. 1, located onshore West of ANWR (figure 1). The BLM also obtained approximately 800 line miles of the original seismic data that was reprocessed by industry to enhance the resolution of seismic reflectors of the shallower Brookian sequence rocks and to help increase the understanding of this sequence. Additionally, some offshore seismic lines near ANWR became available. These new data were used in the current analysis. In addition, an in-house study of the petroleum geology of northeastern Alaska through the Mackenzie Delta in western Canada enhanced the understanding of the regional geology. Surface samples of potential reservoir rocks also were analyzed to assess reservoir parameters. Furthermore, the 1991 assessment utilized a LANDSAT analysis of the bedrock geology of the "bulge" of the mountain front south of the 1002 area.

In August 1990, the Department of Energy's (DOE) Idaho National Engineering Laboratory (INEL) issued a draft study of oil and gas development on the North Slope. This was combined with an in-house analysis and a survey of major companies operating on the North Slope to update the engineering and costing of ANWR development. Updated DOE forecasts of oil prices were also included in the analysis.

Geological and Geophysical Analysis

The new and reinterpreted data resulted in an analysis that, although not vastly different from the 1002 report, gave the BLM a greater degree of confidence in their original recoverable resource assessment of 1987, and also increased their knowledge and understanding of the complicated petroleum geology which exists in and around the 1002 area.

The geology studies and seismic information suggested the necessity of updating correlations of the pre-Ellesmerian basement rocks across the area. Elements of these rocks were important to almost all of the previously mapped prospects. The BLM developed a more detailed description of the depositional systems involved in ANWR stratigraphy. This was important in the Brookian sequence rocks as to their location, extent in the subsurface, and relationship to similar rocks in the Canadian Beaufort/Mackenzie Delta area which have successfully tested and produced oil and gas. The new data provided a higher degree of confidence in determining the nature of geological plays described in the original 1002 Report. This is important to the definition of drilling objectives in the mapped prospects.

The geophysical analysis incorporated the new well data, gravity data, and reprocessed seismic data obtained during the 1983-84 and 1984-85 seasons. The reprocessed seismic data provided better resolution to the seismic reflectors defining the shallow (Brookian) part of the section. This allowed the BLM to map several structural closures within this sequence. These prospects were delineated within the area previously mapped as trends (figure III-10 in the 1002 Report). Most of these new prospects are small and either would not be developed or would be developed in conjunction with the prospects mapped in the 1002 Report, over which the new prospects lie. However, in one case, the prospective target is a stratigraphic prospect of some significance. The gravity data correlated well with the seismically mapped structures of the 1002 area, helping to confirm this aspect of the 1987 Report. Geophysical information from the new wells around ANWR was useful for fine-tuning some of the sonic velocities that were used in the original mapping of the 1002 area. The velocity corrections provided more accurate depths to some of the prospects and also supported the reassessment of prospective reservoirs (drilling objectives) in some of the prospects.

PRESTO Model Inputs

The PRESTO (Probabilistic Resource ESTimates, Offshore) model was used to develop resource estimates. One or more prospective targets were defined for each identified prospect based on the potential for reservoir rocks. Reservoir parameters consisted of risks of no hydrocarbons and probability distributions of the physical characteristics of targets within prospects. Three levels of risk were defined: the risk that no recoverable hydrocarbons existed in the area, in each prospect, and in each prospective target in each prospect. Since gas was assumed to be uneconomic, only four parameters were defined for each target: the probability that the resource is oil (rather than gas), and distributions of productive acreage (acres), pay thickness (feet), and oil recovery factor (bbls/acre-foot). Engineering and economic input for PRESTO consisted of specifying minimum economic field sizes. Minimum recoverable resource sizes were set for each of the prospects.

Reservoir Parameters

The 1991 PRESTO inputs of reservoir parameters evolved from updating the ANWR geologic and geophysical database described above. The changes included the addition of a new stratigraphic prospect mapped in the Brookian sequence, and other new prospects associated with the previously identified prospects. Some PRESTO inputs were derived by an iterative process. After each PRESTO run, the sampled means of the geologic parameters were reviewed to ensure that they accurately modeled the database of the regional geologic parameters. Iterative runs were necessary in cases where choices of the PRESTO input parameters were restricted. In these cases, a decision had to be made on which available input choice most accurately modeled the database of regional geological parameters. These updates resulted in revisions of geological risks, play assignments, and the distributions for unit thicknesses, oil recoveries, and productive acres (or trapfill).

Geologic Risk. Geologic risk played a major part in a PRESTO assessment and was the most subjective of the input parameters. In the 1987 resource assessment, ANWR was studied as a separate basin and considered a frontier area. Using other frontier areas as analogs, a rule-of-thumb approach was used in determining individual prospect risks. No prospect was considered to have a risk of less than 90 percent, i.e. no prospect could have a probability of success of greater than 10 percent. This approach assured that the PRESTO-generated probabilities of economic success would be consistent with other frontier onshore areas of the United States. However, reviews of the ANWR assessment by the National Academy of Science and the Department of Energy suggested that this assumption led to conservative resource estimates and unrealistically low probabilities of success.

The current resource update used the regional petroleum geology study, including the additional well data and the interpretation of reprocessed seismic data, to develop an improved understanding of the stratigraphic framework of the 1002 and surrounding area. With this information, it appeared more appropriate to consider the 1002 area as part of the North Slope oil province, rather than as a rank wildcat frontier area, with ANWR the middle section between the Prudhoe Bay area complex and the discoveries in the Mackenzie Delta area (figure 2). In the North Slope province, hydrocarbons were thought to have been generated and trapped by a variety of mechanisms with the probability of an oil or gas show being very high. Therefore, the probability of a new oil or gas discovery under these conditions was considerably greater than reported in 1987. Consequently, the PRESTO inputs and the geologic prospect risk developed in 1991 reflected this situation, resulting in lower prospect risks and area risk. Each prospect in the 1991 assessment update was studied individually, and each had a risk computed for it derived from the USGS/BLM play risks and the BLM seismic risk. This allowed PRESTO to calculate a conditional economic probability for each prospect and eliminated the previous constraint.

As in the 1987 assessment, this analysis assumed a dependence between prospects. Assuming complete independence implies that all of the prospects in the area would be tested in the course of exploration without incorporating the acquired geologic information that became available as the exploration proceeded. Observations of drilling activities on the North Slope and the current knowledge of the geology of ANWR, resulted in an agreement with the 1987 assessment that only 4 to 6 prospects would be tested in the 1002 area to determine its economic viability. Prospects tested later would be dependent on the results of the first tests.

Play Assignments. Plays were extended or reassessed based on well data, seismic data and the regional geology study; potential reservoirs within prospects were then updated.

Unit Thickness. Adjustments were made to several prospects based on offshore well data and a regional geology study.

Oil Recovery. The oil recovery factor calculations were in part based on the gas-oil ratio (GOR). Literature research showed that the GOR used in the original assessment was conservative and not representative of those found on the North Slope. Oil recovery was recalculated using a more accurate figure for GOR.

Productive Acres or Trapfill. Trapfill is the percentage of the maximum areal extent of the trap that contains recoverable oil or gas. Given the maximum acreage for a trap, the trapfill can be converted to a distribution of productive acres. There is very little information available regarding trapfill. In the 1987 1002 assessment of in-place resources, a play analysis was conducted in which trapfill was represented by a seven point distribution. The assessment of recoverable resources, however, required a prospect analysis and utilization of the PRESTO model. Since the seven-point distribution is not available in PRESTO, a triangular distribution for trapfill was substituted for the calculation of recoverable resources in the 1987 report. However, the 1991 update used a lognormal distribution for trapfill. With the current uncertainty regarding trapfill, it was judged that a lognormal distribution better describes field size distributions found in nature.

Minimum Economic Field Size Analysis

Combining the Minimum Economic Field Size (MEFS) with the reservoir parameters in the PRESTO model produces the economically recoverable resource estimates. The inputs into the MEFS analysis can be grouped into four categories: engineering and costs, taxes, macroeconomics, and reservoir characteristics. The result of the MEFS analysis was a slight lowering of the MEFS. Each prospect has its own MEFS, but overall the MEFS decreased from about 440 million barrels to about 400 million barrels. This figure is applicable to western prospects. The eastern prospects, needing a longer pipeline to reach TAPS, required about 550 million barrels as opposed to the 660 million barrels in the 1002 Report.

The MEFS analysis for the 1002 Report was described in the Appendix, Economics of Oil and Gas Production from ANWR for the Determination of Minimum Economic Field Size, by Young and Hauser (1986). In 1990, the Department of Energy's (DOE) Idaho National Engineering Laboratory (INEL) conducted an extensive literature review, convened public hearings, and collected industry comments for a study of North Slope oil and gas development potential. This included an examination of potential development in the 1002 area. The draft of this study was published in August 1990. The BLM Alaska State Office reviewed this report, compared it with internal information, and followed it with a survey of companies operating on the North Slope to resolve inconsistencies and obtain industry comments on specific data and conclusions presented in the DOE/INEL draft report.

Engineering and Costing. Engineering on the North Slope since the 1002 Report analysis has been more evolutionary than revolutionary. The 1987 1002 analysis had been modeled after the Kuparuk field development. The 1991 analysis incorporated more recent development such as at the Endicott and Milne Point fields which have demonstrated further refinements such as smaller pad sizes that slightly lowered costs and decreased environmental impacts. Endicott is an offshore field developed on gravel islands where space is limited; Milne Point is a small field north of the Kuparuk field.

The major engineering and costing assumption incorporated into this analysis is the stand-alone assumption. This means that development of any prospect must cover all the costs of facilities and transportation requirements by itself. In other words, there is no cost sharing consideration for multiple field development, either simultaneous or sequential. This assumption was used in the 1002 Report. The DOE/INEL study reported tests of some hypothetical examples of multiple small discoveries and noted the resultant impact on minimum economic field sizes. This required them to make assumptions as to which prospects and under what conditions the prospects could share costs, which generally are unreliable and tend to be very subjective. The 1991 update focused on fields with sufficient significance to justify initial development in the 1002 area. Although smaller fields would be economic as a result of this development and would likely be developed later, they are not included in the resource assessment. The engineering and costing focused on minimum economic field sizes since PRESTO only requires the use of this threshold field size.

Exploration assumptions did not change from the 1002 Report: one exploration well drilled into the crest of the prospect the year after leasing, followed by two delineation wells each of the next

3 years into the deepest parts of the prospect. Since there was little recent data available on North Slope exploration, particularly in remote areas, the DOE/INEL study estimated these costs based on the 1002 Report exploration costs. However, BLM's later survey of industry indicated that this estimate was too low. This resource assessment used a cost function based on the industry survey and was consistent with the cost of drilling the KIC well on Native lands within the 1002 area. The BLM will continue to gather engineering and cost information related to new technology, and will consider them in any future updates.

The DOE/INEL study contained an extensive review of production facilities and their costs. The facilities are similar to those used in the 1002 Report, and take into account improvements in the footprint and efficiency. The DOE concentrated on the cost savings from facility sharing. While this is of interest with regard to later development of smaller adjacent fields, the present resource assessment is primarily concerned with initial development. The DOE/INEL estimated a cost surcharge of 15 percent for the first development in a remote area. The BLM's industry survey concurred with DOE's estimates for facilities costs.

The engineering of development drilling has changed little from the 1002 Report. In both the DOE/INEL study and this resource assessment, the number of wells required is still calculated as before. The DOE/INEL hypothesized different categories of development based on field size. For fields relevant to the MEFS analysis, DOE used the same development schedule as the 1002 Report, i.e., 6 years of development drilling with production starting in the 5th year of development and production peaking the year after completing the development. The BLM's industry survey strongly indicated that this was too long as it should be only 5 years of drilling with production starting in the 5th year and peaking the following year. The costs of development provided more disagreement. The DOE estimated a cost function for development drilling based on actual costs in existing fields, demonstrating how costs have declined dramatically over the past decade. However, DOE felt that these costs would not apply to a remote area such as the 1002 area and revised the 1002 Report cost functions, essentially eliminating the cost reductions gained in the past decade. The DOE then applied a learning curve to reduce costs by one-half over 5 years. Industry strongly disagreed with these estimates, indicating that the latest advances used at Endicott and Milne Point fields would also apply to 1002 developments. Costs would initially be somewhat higher than in existing fields, but would quickly drop as infrastructure was built up and the operators became familiar with ANWR. Thus, at depths to fifteen thousand feet, the estimated costs were much less than the DOE costs, in some cases were as low as one-half the DOE cost. At deeper depths costs increased rapidly, approaching DOE's costs at around twenty thousand feet.

Based on the DOE/INEL study and the concurrence of industry, the estimated production schedule was similar to that in the 1002 Report except that these small fields would have a 15 rather than a 12 percent annual decline. This assessment used two refinements in engineering that were introduced in DOE/INEL's North Slope study: using the increasing water cut and the decline in the number of active producing wells. Water cut is the percentage of fluid production that is water. As a field is depleted, the water cut increases. At the start of production, it is assumed that 40 percent of wells drilled are used for injection. As the reservoir gets depleted, some production wells are converted to injection wells. The water cut is used in calculating operating costs, while the number of active producers is used in the severance tax calculation. Analyzing the existing fields on the North Slope, DOE obtained a more accurate representation of production costs based on total fluid production rather than oil production. Industry concurred with these costs and they were used in this resource assessment.

The DOE/INEL reviewed the three components of transportation costs; a pipeline from ANWR to TAPS, a tariff for using TAPS to Valdez, and tankering from Valdez to the lower 48. The TAPS tariff is comparable to the numbers in the 1002 analysis. This assessment used the same spreadsheet used by the State of Alaska to estimate future tariffs, including the costs of corrosion abatement and increased oil spill response capability. The DOE found that the average tanker cost was less than that used in the 1002 Report due to a higher proportion going to the West Coast rather than the Gulf Coast. The DOE did not have data to update the costs for the pipeline from the 1002 area to TAPS and thus used the function from the 1002 Report. However, industry strongly disagreed with this estimate. Based on their own internal studies of a pipeline from the 1002 area to TAPS, industry provided the lower cost estimates used in this resource estimate.

The stand-alone assumption and the facilities and ANWR pipeline costs are the primary factors for determining the MEFS. The development drilling costs also become a major factor for every deep, low yield prospect.

Taxes. Several changes have occurred in taxes since the 1002 analysis. The Federal tax code has changed but generally had little effect. Assuming development by a major oil company, the modification of the tax deductions is offset by the reduction in the corporate tax rate. The minimum tax provisions were assumed to have no impact. The State altered its severance tax by raising the tax for very large fields. Since this analysis is looking for the minimum economic field size, this change had only a marginal impact.

Macroeconomics. The macroeconomic assumptions covered four areas: discount rate, oil prices, the role of natural gas, and inflation. The discount rate used in this assessment was the same used by Young and Hauser for the 1002 Report, i.e., a real after-tax rate of 10 percent. The oil price scenario used was the DOE National Energy Strategy Reference Case. This resulted in a lower price schedule than that used in the 1002 Report, but was closer when taking into account the delay in opening the 1002 area of ANWR. Natural gas was still assumed to be uneconomic for purposes of estimating the MEFS due to the uncertainty of available transportation and the huge reserves already available on the North Slope. Although the gas eventually may be developed, the decision to develop the 1002 area in the next 10 years will not depend on the development of natural gas resources. Inflation is assumed to average four percent a year rather than the six percent used in the 1002 Report. This figure is comparable to inflation rates used in the DOE report and long range analyses by firms as DRI/McGraw-Hill. Since inflation was incorporated in cost and price escalation as well as the nominal discount rate, the impact on the MEFS was marginal. The decline in the price estimates was offset by the decline in the costs, resulting in the lower MEFS.

Reservoir Characteristics. The reservoir parameters previously described were used in estimating the MEFS. For each prospect, a risk-weighted average oil recovery factor was calculated, conditioned on the existence of hydrocarbons in the prospect. In testing a resource size for the MEFS, the average recovery was used to calculate the number of acres required to contain oil. If the acres required exceeded the areal extent of the prospect, then the maximum productive acreage was used, increasing the recovery factor to that necessary to yield the tested resource size. The acreage in turn determined the number of wells needed to develop the prospect.

PRESTO III Analysis Results

The results of this new study show that at the mean, there are 3.57 billion barrels of conditionally economically recoverable oil resources for the 1002 area with a marginal probability of economic success of 46 percent. The large increase in the marginal probability was due to:

1. Adding a reservoir to some of the prospects which made their economic probability greater;
2. Increasing the number of mapped prospects;
3. No longer considering the 1002 area as a frontier area for oil exploration and not constraining the individual prospect probability of success; and
4. Having a slightly smaller economic field size.

Conclusion

Mineral assessment is a dynamic process. As new information becomes available, it will be necessary to review previous assumptions and models and, if necessary, make adjustments to previous assessments. The BLM has gained considerable experience and improved its expertise in analyzing the complicated foreland fold and thrustbelt type geology which exists in ANWR. The 1991 ANWR assessment update has reaffirmed the previous resource estimates and increased the confidence that these resources will be found. This confidence level is reflected in the increase in the marginal probability from 19 percent to 46 percent.

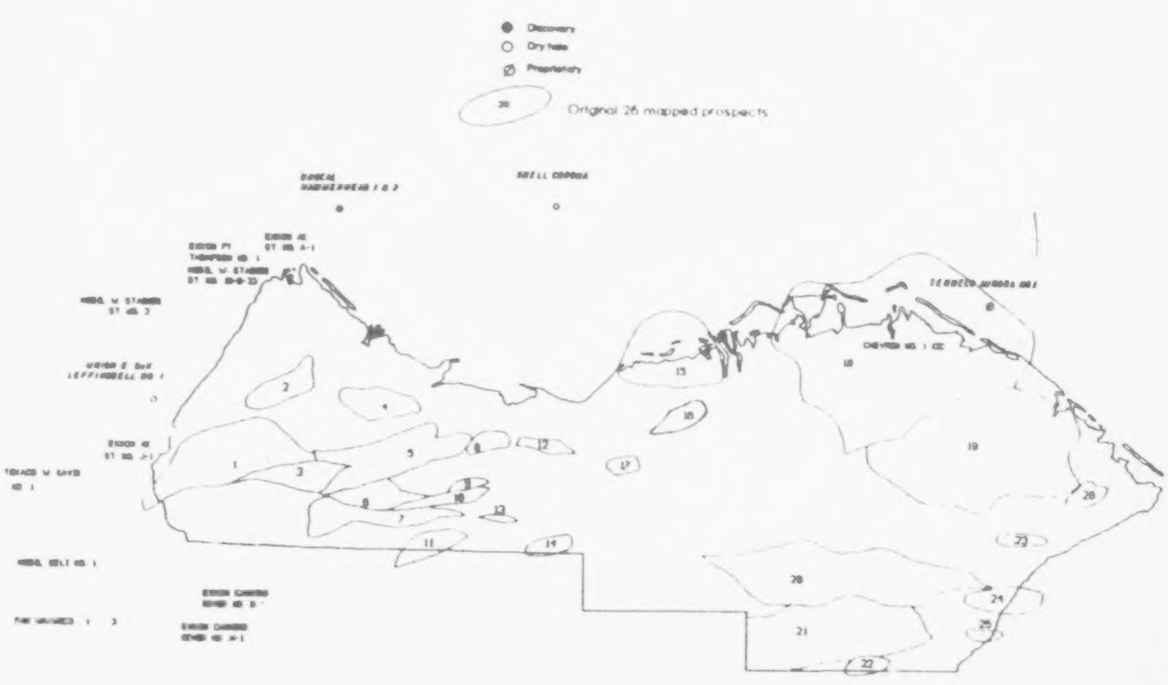

● Discovery
○ Dry hole
Ø Proprietary
20
Original 26 mapped prospects
SHELL CORONA
TENNECO AURORA NO 1
CHEVRON NO. 1 KIC
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26

Fig. 1 Pertinent wells studied for 1990 ANWR Update

(Well locations approximate, KIC well not studied)

(Extracted from Banet, Foland, Lalla 1990)

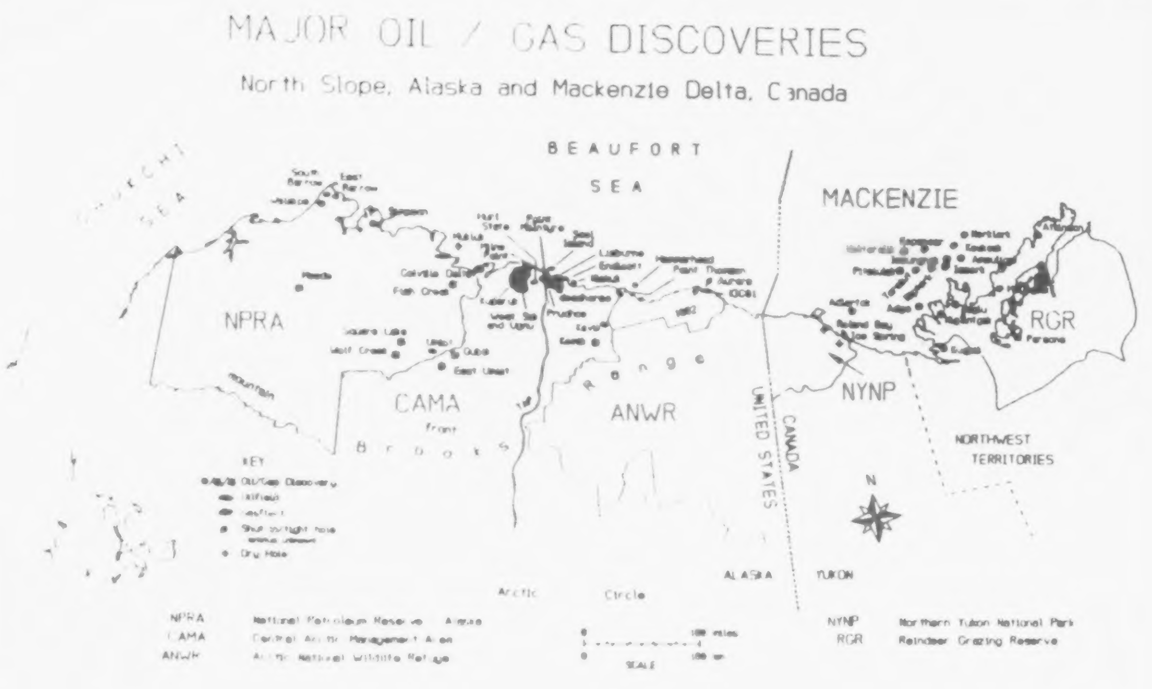

MAJOR OIL / GAS DISCOVERIES
North Slope, Alaska and Mackenzie Delta, Canada
BEAUFORT SEA
SEA
South Barrow
East Barrow
Walakpa
Simpson
Peard
Hurl State
Point McIntyre
Seal Island
Kuvlum
Milne Point
Lisburne
Endicott
Colville Delta
Fish Creek
Kuparuk
West Sak and Ugnu
Prudhoe
Niakuk
Hammerhead
Point Thomson
Aurora
Kavik
Kemik
Square Lake
Wolf Creek
Umiat
Gubik
East Umiat
NPRA
CAMA
ANWR
Brooks Range
Front
mountain
1002
MACKENZIE
NYNP
RGR
Roland Bay
Parsons
UNITED STATES
CANADA
ALASKA
YUKON
NORTHWEST TERRITORIES
N
Arctic Circle
KEY
Oil/Gas Discovery
Oilfield
Gasfield
Shut in/tight hole status unknown
Dry Hole
NPRA National Petroleum Reserve - Alaska
CAMA Central Arctic Management Area
ANWR Arctic National Wildlife Refuge
NYNP Northern Yukon National Park
RGR Reindeer Grazing Reserve
0 100 miles
0 100 km
SCALE

Fig. 2 Northern Alaska/Canada Oil & Gas discoveries
(From Banet 1990, in press)

OFFICIAL COMMITTEE FILE
PLEASE RETURN

US Department
of Transportation
**United States
Coast Guard**

Commandant
United States Coast Guard

Washington, D.C. 20593-0001
Staff Symbol G-CC/104
Phone (202) 366-4280

RGY AND NATURAL RESOU
RECEIVED
WASHINGTON, D.C.

APR 19 1991

5730

The Honorable J. Bennett Johnston
Chairman, Committee on Energy and
Natural Resources
United States Senate
Washington, DC 20510

Dear Senator Johnston:

The attached Questions and Answers for the Record are provided pursuant to your Committee hearing on March 12, 1991, on Energy Security Act (S. 341). All responses have been reviewed and approved, as required, by the Department of Transportation, and the Office of Management and Budget.

Please do not hesitate to call if I can provide further assistance.

Sincerely,

J. D. Hull
Captain, U. S. Coast Guard
Chief, Congressional Affairs Staff
By direction of the Commandant

Copy: Senator Malcolm Wallop
Senator Frank H. Murkowski

RGY AND NATURAL RESOU
RECEIVED
WASHINGTON, D.C.

QUESTIONS SUBMITTED BY SENATORS WALLOP AND MURKOWSKI

SENATOR WALLOP AND SENATOR MURKOWSKI: Alyeska Pipeline Co. has been required to update their oil contingency plans and conduct exercises/drills to test their preparedness. Has the Coast Guard participated in these efforts, and are Alyeska's preparations adequate?

ANSWER: The Coast Guard Marine Safety Office Valdez has played an active role in the development of Alyeska's comprehensive contingency plan and has participated in all of Alyeska's pollution response drills. The oil pollution response capability of Alyeska has dramatically improved since the Exxon Valdez spill. They have assembled an impressive pollution response inventory, second to none in the country; the largest U.S. belt skimmer (125'), a 415' tug/barge dynamic skimming vessel, a 471' lightering vessel, a 207' weir boom response vessel, two oil storage barges, four 210' Escort Response Vessels, and 31,000 feet of containment boom. In addition, they have stockpiled dispersants and dispersant application equipment. In summary, Alyeska has been proactive in responding to the increased expectations developing from OPA-90, state requirements, and public concerns. While they are still upgrading their response capability, building their inventory, and training, major progress has been made.

SENATOR WALLOP AND SENATOR MURKOWSKI: Fully realizing that you can't make a prediction with any certainty, and with the extraordinary measures we have put into place to ensure we will not have another incident like that of the EXXON VALDEZ, in your best estimation can you give us a percentage chance of that situation ever occurring again? And providing the Committee with that figure, do we have the same type of controls and measures in place to ensure that non-U.S. flag ships entering our ports will have the same type of accident-free statistics?

ANSWER: It is impossible to provide a percentage chance of the potential for another EXXON VALDEZ incident occuring. With the safeguards now in place, additional safety factors would have to fail for a similar grounding to occur. The Coast Guard's radars have been improved to cover a larger area, and the Vessel Traffic Service (VTS) watchstanders now monitor vessel movements past the Bligh Reef area. In addition, the manning of the VTS has been increased. Tankers are now escorted by two Ship Escort Response Vessels (SERVS), and a pilot is required to be on the bridge of the tanker, in addition to the master. All of these elements provide a greater safety net. Over 8,000 safe transits were made in 12 years even without these additional safeguards. One should expect an extremely low probability of an EXXON VALDEZ incident occurring again at Valdez with these additional measures in place.

The safeguards described above are also in place for foreign flag tankers operating in Prince William Sound. However, some of these safeguards are unique to Valdez, and no other port in the U.S. has all of the elements of this comprehensive safety net in place.

SENATOR WALLOP AND SENATOR MURKOWSKI: How would you describe the condition of the Sound today?

ANSWER: The Sound is recovering remarkably well! The response effort undertaken by Exxon, combined with natural recovery processes, have all but eliminated any visible signs of the oil spill. Bear in mind that over 50% of the Sound escaped virtually unscathed by the spill. The portions that were heavily impacted by the spill have substantially recovered also. A visitor, unfamiliar with the area, would now have a difficult time finding any oil. The cultural, ecological, recreational, and economic aspects are essentially back to pre-spill conditions. The wildlife is abundant and the fisheries are very strong. A few miles of discontinuous shoreline remain on which oil is trapped in rock crevices, exists on the surface as tar mats or tarballs, or is subsurface and covered with sand and gravel. This oil is the focus of the current response operation. Most of the surface oil will be removed however, it is impossible to recover all tar balls. Additionally, some oil will remain a few feet below the surface and biodegrade naturally over time. The toxic properties of this oil have been minimized.

Alyeska pipeline
SERVICE COMPANY

1835 SOUTH BRAGAW STREET ANCHORAGE ALASKA 99512 TELEPHONE (907) 278-1611 TELEX 090-25-127

April 16, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510-6150

Dear Senator Johnston:

In response to your March 19, 1991 request, my answers to the additional questions posed by Senators Wallop and Murkowski are below. I apologize for the delay and hope this letter arrives in time for inclusion in the Hearing Record. I would like to thank the Committee for the courtesy extended me and for the opportunity to inform the Committee of the positive job Alyeska Pipeline Service Company (Alyeska) has done in transporting North Slope oil. We look forward to the ultimate opening of the Coastal Plain of the Alaska National Wildlife Refuge (ANWR) for responsible and environmentally sound oil production, as provided in S. 341.

1) It has been said that government oversight of Alyeska has been insufficient. Would you comment? How many agencies have oversight now? Is this greater or lesser than other pipelines?

The Trans Alaska Pipeline System (TAPS) is to my knowledge the most regulated pipeline system in this country. Its Owner Companies are all common carrier pipelines subject to tariff regulation on the federal level by the Federal Energy Regulatory Commission and on the state level by the Alaska Public Utilities Commission. By the terms of the Agreement and Grant of Right of Way for the Trans Alaska Pipeline System, Alyeska, as the operator of TAPS for its common carrier pipeline Owner Companies, is subject to oversight by the Branch of Pipeline Monitoring, Bureau of Land Management, Department of the Interior. Similarly, for those portions of the pipeline that are held pursuant to state lease, Alyeska reports to the Pipeline Coordinator for the Alaska Department of Natural Resources. The federal Hazardous Liquids Pipeline Safety Act subjects TAPS to oversight by the Office of Pipeline Safety, Research and Special Projects Administration, Department of Transportation. Additionally, Alyeska's activities receive ongoing scrutiny from the Alaska Department of Environmental Conservation and the Environmental Protection Agency in connection with permits for air and water emissions, hazardous materials, hazardous wastes and other environmental concerns. Permitting agencies include the U.S. Army Corps of Engineers, U.S. Fish and Wildlife Service, State Department of Fish and Game, Alaska Coastal Zone Management Commission, and numerous local agencies. Alyeska's facilities and activities are also subject to inspection by the U.S. Coast Guard, the State Department of Labor and the federal Occupational Safety and Health Administration.

Because regulation of Alyeska and TAPS is so pervasive, it is virtually impossible not to err by excluding some entity from a list of agencies asserting regulatory oversight of some form or another. We doubt that any other common carrier pipeline received such rigorous government scrutiny during its authorization and construction. Moreover, in the fourteen years that TAPS has been successfully transporting North Slope oil, it has been the subject, directly or indirectly, of nine audits by the General Accounting Office, two of which are ongoing.

We do not believe that government oversight of Alyeska is insufficient. The recent Memorandum of Understanding among the Alaska Department of Natural Resources, Office of Pipeline Safety and Department of Interior establishes a joint office comprised of these TAPS oversight agencies. This will, in our view, functionally improve and streamline the regulatory process.

The citizens' involvement contemplated by the Oil Pollution Act of 1990 and the state legislation creating the Alaska Citizens Oversight Council assures that the public interest in the continuing safe operation of the transportation of North Slope oil is represented in the regulatory process. Additionally, Alyeska voluntarily funds, at an annual cost of $2 million, a Regional Citizens' Advisory Council consisting of residents of Prince William Sound communities and environmental and fishing industry groups. In the end, it is the vigilance of the ordinary citizen, the people with the greatest stake in the soundness of our activities, that will assure attentive government oversight. To accomplish this purpose, further tiers of regulators are not necessary or useful.

2) Newspaper reports give the impression that pipeline corrosion is so serious that ANWR should not be produced. Is that true?

No. All buried steel pipelines are subject to corrosion. Every reasonable step is taken in the design and construction of a pipeline to minimize corrosion but it would be highly inadvisable for any pipeline operator to assume that the precautions designed into a system were sufficient to eliminate all possibility of corrosion. The touchstone of any corrosion program is constant vigilance and an orderly plan of preventative maintenance. Alyeska has had such a plan since its operations began in 1977. We have consistently complied with the requirements of federal law that mandate inspection of the pipeline for corrosion whenever the pipe is uncovered. Over 1200 inspection reports are on file at Alyeska documenting its corrosion quality control inspections. Contrary to what one gathers from the media, Alyeska foresaw that the line would be subject to corrosion. We worked with vendors to improve and develop new corrosion detection technologies. We also developed a program for dealing with the indications of corrosion from our detection equipment and we are carrying out that program. With the continued vigilance provided by our corrosion minimization monitoring, and repair activities, Alyeska is confident TAPS will transport North Slope oil as long as there is oil to move and it is economic to do so.

3) It will be alleged that the Alaska Department of Environmental Conservation has said ballast water passes through the Valdez Ballast Water Transfer untreated. Is this true?

We are not aware of any statement by the Alaska Department of Environmental Conservation (ADEC) that the Ballast Water Treatment facility at the Valdez Marine Terminal operates, or has operated in the past, in a manner that results in untreated ballast water being discharged into the waters of Port Valdez. Such a statement would be patently untrue. Alyeska is presently operating that system pursuant to a discharge permit issued by EPA and certified by ADEC as complying with Alaska water quality standards.

4) What about Ballast Water Transfer -- is it industry practice? What harm is done? What are BWT operations?

According to several tanker operators, ballast water is occasionally transferred from one ship in the TAPS trade to another ship bound for Valdez in accordance with industry practice. No harm is done as long as the oily ballast is not contaminated with other substances that might hinder its subsequent treatment.

Tankers that call at the Valdez Marine Terminal to load oil for delivery to the Lower 48 arrive with non-segregated ballast water in the tanks that carry oil on the trip south. Tankers carry ballast water during the voyage north to provide stability. Before loading at Valdez, the tankers pump this oily ballast ashore for treatment. The International Convention on Oil Pollution of the Seas (the MARPOL Convention) and its amendments regulate the discharge of oily ballast at sea by tankers or shore-based reception facilities. The federal Agreement and Grant of Right of Way for the Trans Alaska Pipeline System anticipated United States' ratification of the MARPOL Convention by requiring Alyeska to build and operate a wastewater treatment facility at Valdez and to receive and treat all oily water discharged from vessels in the TAPS trade calling at the Valdez Marine Terminal.

Initially, the ballast water treatment facility in Valdez was an oil/water separation process, consisting of large separation tanks, dissolved air flotation cells and two large settlement basins. The federal authorization for the pipeline and Alyeska's first discharge permit required that the effluent be monitored only for oil and grease content. The permitting scheme of the Federal Water Pollution Control Act, as embodied in the National Pollutant Discharge Elimination System (NPDES), continually reduces the level of pollutants discharged from point sources by imposing stringent limits to the extent achievable or necessary.

Alyeska has worked with the EPA and ADEC in improving the ability of the ballast water treatment system to eliminate pollutants from the plant's effluent. On its own initiative Alyeska developed a biological treatment system, to our knowledge the first such system to operate successfully on a large scale in a severe cold weather environment. As a result, certain pollutants in the facility effluent such as naphthalene, which can accumulate in the livers of bottom feeding fish, were decreased to below detection levels. Similarly, aromatic hydrocarbons, such as benzene, were significantly reduced to levels that assure compliance with the Alaska Water Quality Standards, perhaps the most stringent such standards in the United States. I enclose with this letter a detailed summary of the Operations, History and Effects of Alyeska's Valdez Marine Terminal Ballast Water Treatment for the Committee's further edification. (Attachment 1).

5) It has been alleged that hydrocarbon derivatives have been found in the gall bladder of pollock 600 miles from Valdez. Do you have any comment?

The National Oceanographic and Atmospheric Administration has been conducting studies throughout the waters of the United States, both pristine, as in Valdez, and polluted, as in Boston and New York harbors. These studies demonstrate the pervasiveness of pollution in the marine environment. Petroleum hydrocarbons occur naturally from sub-sea seepage in many areas, including off-shore Alaska and the Santa Barbara Channel. They also enter the marine environment from recreational as well as industrial use of the seas. Although we do not know the specific results to which you refer, we are aware of similar findings in Port Valdez. A bottom fish was found to have metabolites of benzo-a-pyrene and naphthalene in its liver. That fish was found across the bay from the Valdez Marine Terminal and near a location where a significant amount of refined petroleum products were discharged into Port Valdez as a result of the 1964 Good Friday earthquake. Benzo-a-pyrene is a product of combustion emissions -- principally forest fires or smoke from wood burning stoves -- while naphthalene, the trace hydrocarbon normally associated with oil pollution, has not been detected in the ballast water effluent discharge from the terminal since Alyeska, at its own instigation, initiated biological treatment.

Finally, many noted scientists have studied the Valdez marine environment to determine whether or not Alyeska's operations have had any detectable effect on it. This month, scientists from the University of Alaska's Institute of Marine Science issued a report that stated:

> In summary, as concluded in all previous reports (e.g., Feder and Shaw, 1986, 1988, and 1990), all techniques used in the analyses of infaunal data from 1971-1990 indicate that once construction activities were completed, marine terminal

> activities did not affect the organisms in the Deep Basin (Far-Field and Mixing-Zone stations), the intermediate depth Mixing-Zone station, and Near-Field and shallow Mixing-Zone stations (with the possible exception of Station D33).

Station D33 is adjacent to the wastewater discharge point and may have experienced a minor negative disturbance as a result of the wastewater output. A copy of the report's executive summary is attached. (Attachment 2). A listing of studies of the Valdez marine environment is also enclosed. (Attachment 3). Should you wish copies of any of these publications, we will be pleased to assist you in obtaining them.

6) What percentage of the pipeline is actually affected by corrosion?

Based on the most recent surveys of the pipeline with corrosion detection devices, areas totalling less than 16 miles of the 800 miles, or less than two percent of the mainline pipe, demonstrate indications of significant corrosion.

7) If we do not drill in ANWR and the pipeline eventually shuts down, and ten years from now we decide to open ANWR, what is involved in reopening the pipeline? How much would that cost?

Under the terms of the federal Agreement and Grant of Right of Way for the Trans Alaska Pipeline System and the state Right of Way Lease for the Trans Alaska Pipeline System, once the pipeline is no longer moving oil, the Owners of TAPS are required to dismantle and remove the pipeline and its related facilities and restore the environment that has been disturbed by pipeline operation to the satisfaction of the Authorized Officer. Relief would have to be granted from these provisions in order to allow the pipeline to be mothballed while awaiting ANWR production. The feasibility and expense of mothballing this 800 mile facility has not been determined. If that relief were not granted, the cost of constructing a new transportation system in order to develop the reserves contained in ANWR would probably make development economically impossible. It is the presence of TAPS, a proven, environmentally sound transportation system for North Slope oil, that makes the development of ANWR possible now.

Again, may I express my appreciation for the courtesy extended to me and to Alyeska by your Committee. I hope you find my testimony and the responses to your additional questions useful. We will gladly continue to assist the Committee in any way we can including providing tours of our facilities in Alaska to you or any of your staff members should you find this useful.

Very truly yours,

Jim Hermiller

James B. Hermiller
President and CEO

Enclosures

cc: Senator Frank H. Murkowski
Senator Malcolm Wallop

ATTACHMENT 1

VALDEZ MARINE TERMINAL BALLAST WATER TREATMENT

- Operations, History and Effects -

February 1991

VALDEZ MARINE TERMINAL BALLAST WATER TREATMENT

- Operations, History and Effects -

I. BWT Operations

  A. Elements
  B. Facilities

II. BWT History

  A. The Law and Permits
  B. Standards and Compliance

III. BWT Effects

  A. Environmental Studies
  B. Conclusions

I. BWT OPERATIONS

A. ELEMENTS

Tankers arriving at Alyeska's marine terminal in Valdez almost invariably contain ballast water: seawater taken on for stability by tankers after they have delivered their cargo at the prior port of call. When carried in a ship's tanks which are otherwise used for oil, the ballast water becomes contaminated with the remnants of the oil previously contained there.

This "non-segregated" ballast must be discharged into the ballast water treatment (BWT) system for processing by Alyeska. The oil content of the ballast water as it is pumped from the vessels is usually less than 1 percent.

The Alyeska BWT system has a two-fold purpose: (1) to recover crude oil from the ballast water and (2) to separate and process the water in order to return it safely to the sea. The residue oil separated out during treatment is returned to the crude oil system. The remaining water, when processed sufficiently to remove contaminants, is discharged through a diffuser into the waters of Port Valdez.

During the past 13 years, more than 10,000 tankers have arrived at the Alyeska terminal in Valdez. The BWT facilities process about 16 million gallons of ballast water daily.

B. FACILITIES

The Alyeska BWT system has been an integral part of the Trans Alaska Pipeline System since its inception. Although the BWT plant was designed initially to remove oil and grease compounds, the process also removed some aromatic hydrocarbons. The regulations at the time required only oil and grease removal. The BWT system now involves a three-step process as illustrated in Attachment 1 and described below: two steps to remove insoluble oil and one step to treat the soluble fraction of the oil in the water.

Settling Tanks

After a vessel docks at the Valdez terminal, the ballast water is piped to one or more of three settling tanks for the initial stage of oil recovery. Each of the three tanks has a 430,000 barrel capacity. Oil naturally floats on water, and the oil separation process uses this principle.

As the oil floats to the surface of the water, floating skimmer pans siphon off the oil from the top of the tank. The oil is then piped to one of two oil storage tanks nearby where it remains until it is returned to an outgoing vessel. This initial oil recovery process is usually complete in less than four hours.

Dissolved Air Flotation

The water which has been clarified through the separation process in the settling tanks then flows through a pipe to the Dissolved Air Flotation (DAF) chambers, a special recovery plant containing six cells, for further oil recovery. This stage of the BWT process relies on microscopic bubbles of air and a polymer to accelerate the process of separating the remaining oil from the water.

The air bubbles and the polymer attract the oil molecules and cause them to float to the surface. The polymer forms a sticky microscopic lattice in the water. The air bubbles float the polymer to the surface, attracting and holding together the oil molecules which have risen to the tops of the DAF cells. The recovered oil is piped to one of two oil storage tanks, and the waters flow on to the impound basins for biological treatment.

BWT/3

Biological Treatment

In the early days of operation, Alyeska's impound basins were used for final collection prior to discharge. If upstream processes did not work properly, then the contents of the basins could be recycled for further treatment. The two parallel impound basins, each approximately 380' by 225' by 13' deep, have sloped sides, except for the discharge ends which are vertical concrete walls. Surface underflow and overflow weirs retain any surface pollutants. The working volume of each basin is approximately 135,000 barrels (5,500,000 gallons).

In 1986, Alyeska decided, on its own, to add a biological treatment process in the two impound basins. The process is based on the discovery that, if the proper conditions exist, certain microbes will 'eat' dissolved oil molecules converting this oil to carbon dioxide, water and more organisms. Specifically, the microbes reduce the concentration of water soluble chemicals (aromatic hydrocarbons) which are present in the crude oil and become dissolved in the ballast water, four of which are collectively known as BETX (benzene; ethylbenzene; toluene; xylene).

The number of microbes which are found in the ballast water from the ships varies depending on where the vessel picked up the ballast water, how long the ballast water has been in the oil tanker and the degree to which the tanker's voyage involved agitation or calm sailing. The BWT system operators work to ensure a proper environment to increase both the population and activity of these oil-eating microbes.

The microbes live in water and need oxygen and nutrients to metabolize the BETX. The ballast water acts as a seawater medium to which nitrogen and phosphorous are added as nutrients. Oxygen is added through the use of aerators which float on the surface of the impound basins. Like most living things, the microbes occasionally perform at less than optimal levels, causing an 'upset' or rise in BETX levels to occur. As seen in Attachment 2, such upsets have not exceeded the current permit limit. Since March of 1990, the monthly average has flattened out altogether.

Because of recent and pending Federal regulations, Alyeska is building new treatment facilities. A new concrete structure, separated into two large tanks, will replace the lined impound basins which have been in use since 1977. The two concrete tanks will facilitate further improvements in the biological treatment process, particularly in mixing, aeration and process controls.

Air strippers will be installed at the end of each of the new tanks and will be used only if necessary to handle the infrequent occasions when an 'upset' has occurred and the oil-eating activity of the microbes decreases. Without the air strippers, these occasional upsets could result in BETX effluent concentrations above regulated levels. The new facilities are due to be operational by February of 1991 and will cost approximately $30,000,000.

After biological treatment, the ballast water then flows to an outfall line which terminates at the diffuser. The outfall diffuser system was designed to maximize the dilution of the treated ballast with the natural waters in Port Valdez. The treated water travels a distance of 1200 feet in the pipe before reaching the first diffusion port or outlet.

Effluent is discharged through 20 diffuser ports spaced at approximately ten-foot intervals. Water depths along the 200-foot long diffuser range from 200 to 270 feet. Diffusion takes place in the "mixing zone," the area of water near the terminal where mixing is permitted and where compliance with State water quality standards is measured.

II. BWT HISTORY

A. THE LAW AND PERMITS

The Clean Water Act

The objective of the Federal Water Pollution Control Act (U.S.C. 466 et seq.), now known as the Clean Water Act, is to restore and maintain the chemical, physical and biological integrity of the Nation's waters.

Under the Clean Water Act, Alyeska is required to obtain a National Pollutant Discharge Elimination System (NPDES) permit in order to discharge processed water from the BWT facility. The Environmental Protection Agency (EPA) has the authority for issuing the NPDES permit which can be in effect for any period up to five years. If EPA fails to issue a new permit in a timely manner, the provisions of the previous permit remain in effect until the new permit is issued.

Although the responsibility for developing and issuing the permit rests with the EPA, the Alaska Department of Environmental Conservation (ADEC) is authorized to add to NPDES permits such provisions as are necessary to meet State water quality standards or are otherwise related to water quality. Water quality standards are enforceable limits placed on concentrations of a pollutant in the receiving water. ADEC must certify that the water discharged under an NPDES permit meets State water quality standards before EPA can issue the permit.

The First Permit

The first NPDES permit for the BWT was issued in 1975, two years prior to start-up of the pipeline and three years after the passage of the Clean Water Act. It placed limits on oil and grease, acidity and flow volumes. These categories of limits are standard practice worldwide for such facilities, and, as seen in Attachment 3, these are still the only three categories of limits required at the Sullom Voe terminal in the Shetland Islands of Great Britain today.

Additionally the original permit required Alyeska to develop a monitoring program to determine the effects of the ballast water discharge on water quality and marine biota of Port Valdez. Prior to the beginning of terminal operations, the University of Alaska's Institute of Marine Science (IMS) conducted baseline studies to obtain data to use comparatively in subsequent monitoring studies.

The Second Permit

The second NPDES permit was issued to Alyeska in 1980. The limits on oil and grease (reported as total hydrocarbons) were unchanged, but the EPA imposed reductions on discharge volumes. The permit also required Alyeska to conduct monitoring studies.

With this permit, the EPA additionally imposed limits, for the first time, on aromatic hydrocarbons, specifically BETX -- substances which had coincidentally been removed in the BWT facility without regulation. The limits imposed on BETX were based on performance studies of the treatment plant and were set at 6 parts per million (ppm) for a daily average and 9 ppm for a daily maximum. Besides imposing specific restrictions for BETX, the EPA also required a study of available technology to reduce BETX.

In response, Alyeska invested heavily in research to find the best way to gain control over and further reduce BETX. Among the methods investigated was biological treatment. Experts were unsure, however, whether the biological treatment method would work in the specific environment at Valdez.

More studies revealed that, despite the relative cold in Valdez and other adverse conditions, biological treatment might indeed be the answer. In 1986, after a series of bench tests, Alyeska decided to try full scale biological treatment. Soon it became apparent that the biological process was a resounding success: the average reduction of BETX varies between 80 and 90 percent.

This permit expired by its terms in June 1983. Alyeska had applied for renewal eleven months before, but EPA did not issue a new permit until 1989. In the meantime, the facility continued to operate under the second permit.

The Third Permit

The third NPDES Permit was issued in May 1989 and is still in effect today. Discharge limitations are significantly more strict. BETX has to meet a 1.3 ppm daily maximum limit year-round. As seen in Attachment 3, the Sullom Voe terminal, which is roughly the same size and latitude of the Valdez terminal, has no such requirements. The EPA gave Alyeska until October 1991 to meet the new BETX standards.

Additional limits were placed on napthalene, a polynuclear aromatic hydrocarbon, to below detection limits. Polynuclear aromatic hydrocarbons (PAH) are considered more persistent than BETX and tend to accumulate in marine organisms. The biological treatment process already reduced PAH to below detection levels as required by the permit. Limits on flow were reduced, moreover, and new limits were also placed on the total amount of solids and organic material present in the water.

Stipulations of the present permit also include conducting effluent toxicity tests. The tests required are (1) chronic (sublethal) tests on sea urchin and mussels and (2) acute (survival) tests on shrimp and pink salmon. Biological, sediment and tissue monitoring is also mandated. The permit also establishes a Technical Advisory Group that has been meeting and making recommendations to ADEC and the EPA.

B. STANDARDS AND COMPLIANCE

Water Quality Standards

The EPA publishes criteria intended to provide technical guidance to State governments for the establishment or water quality standards. These State standards then become enforceable limits placed on concentrations of a pollutant in the receiving water. In early guidelines for developing water quality standards in the mid 1970s, EPA recommended that, where long term/chronic toxicity data were unavailable, short term/acute toxicity levels could be divided by a very conservative and arbitrary safety factor of 100 to establish standards intended to protect against chronic (i.e., long term) exposure.

As more data on the relationship between acute and chronic toxicity became available, EPA issued new guidelines which made clear that a ratio of 100-to-1 was reserved for compounds that demonstrated little or no degradation in aquatic ecosystems, e.g., persistent chemical compounds such as chlorinated pesticides. For nonpersistent, degradable compounds (such as BETX), a ratio of 20 to 1 or less was considered by EPA to be more in line with available data.

BWT/8

In 1979, ADEC revised its water quality standards for the State of Alaska. At that time, there were few data on the long-term effects of hydrocarbons on marine species. ADEC set a receiving water limit of 10 parts per billion (10 ppb) for total aromatic hydrocarbons.

The State decision was apparently based on (1) a study of reported short term/acute lethal threshold concentration levels for several species of larval crustaceans found in the literature of the time and (2) applying the then recommended EPA 'safety factor' for non-biodegradable toxins of 100-to-1.

Alyeska has voiced objections to ADEC's approach. EPA's guidelines for setting water quality standards were revised in 1985 in light of more recent scientific studies. EPA's recommended approach is to utilize actual test results, where available, and to use arbitrary safety factors only as a last resort. ADEC's standard for aromatic hydrocarbons conflicts with current scientific data and is far more stringent than what is now known to be necessary to protect aquatic life.

EPA Compliance

In 1985, responding to public concern about BWT operations, the EPA issued a Compliance Order listing 12 items to be investigated. Three years later, after EPA had completed a detailed investigation of allegations that the Alyeska facility had violated its NPDES permit, Alyeska received a letter from EPA's Regional Administrator which stated as follows:

> "The investigation included interviews with Alyeska employees, ship's crews, and other people familiar with the ballast water treatment operation, a review of EPA and Alaska Department of Environmental Conservation files, review of Alaska Public Utilities files, and a review of ship deballasting records and Alyeska ballast water treatment records. . .

> "The recommendation resulting from that review is that no additional formal enforcement action against Alyeska is appropriate at this time. We arrived at this conclusion because the allegations could not be substantiated or have already been addressed by EPA and resolved by Alyeska as a result of previous Section 308 and Section 309 actions."

III. BWT EFFECTS

A. ENVIRONMENTAL STUDIES

There is an extensive body of scientific literature on Port Valdez, compiled during numerous studies conducted since 1971. As would be expected, there have been detectable amounts of hydrocarbons in the environment, at various locations in the water column and sediments. Some are related to human activity: BWT operations; ash settling in the water from wood burning in fireplaces; combustion sources, such as boat engines, and minor oil spills. Greater concentrations of PAH (polynuclear aromatic hydrocarbons) were found in 1985 in mussels and sediments in the Valdez small boat harbor than near the ballast water outfall.

Hydrocarbon found in the water can also emanate from natural sources, not attributable to human activity. Some marine algae produce certain kinds of hydrocarbons. Terrestrial plants also produce hydrocarbons. Activities of nature also affect the marine environment, e.g., mud slides, high runoff from storms and water temperature changes. The 1964 earthquake had a profound effect on Port Valdez. Observers have found fluctuations in the diversity, abundance and total weight of benthic (bottom dwelling) organisms over time, but these are believed to be related to such activities of nature or to specific construction projects as opposed to routine BWT operations.

The key question is whether hydrocarbons from the BWT discharge have caused any significant harm to marine life. The University of Alaska's IMS has conducted a series of studies of Port Valdez beginning in 1971 and continuing to 1987. As a result of this work,

BWT/10

Dr. Howard Feder of IMS concluded that ". . . once construction activities were completed, terminal operations did not affect the organisms on the bottom either in the deep basin or within the mixing zone."

Further, a study conducted in 1987 found that levels of aromatic hydrocarbons in the sediments near the BWT outfall are actually decreasing. The study, "EPA-ADEC Proposal for Monitoring Sediment Chemistry and Infauna in Port Valdez for the Fall of 1987," conducted by the IMS, also found that the diversity, abundance and total weight of benthic (bottom dwelling) organisms increased between 1985 and 1987. Significantly, the biological treatment facilities, voluntarily put in place by Alyeska in 1986, have reduced BETX levels by between 80 and 90 percent on average, and PAH has been reduced to below detection levels.

Two scientists assembled a monograph on Port Valdez during the time the biological treatment facilities were being put into place. The monograph, Environmental Studies in Port Valdez, Alaska, contained papers by various scientists and regulatory officials with extensive knowledge of the Port. The scientists who assembled the monograph were David G. Shaw of the University of Alaska's Institute of Marine Science (IMS) and Mohammad J. Hameedi of NOAA (the National Oceanic and Atmospheric Administration of the U. S. Department of Commerce).

Regarding the quality of the environmental studies done to date, the following was written by Dr. Donald W. Hood, Professor Emeritus, University of Alaska in the Foreward to the monograph: "The studies (of Port Valdez). . . have been well planned, of the highest quality, and well documented in open literature. The overall study effort certainly ranks among the best ever done on a marine ecosystem." Hood affirms the findings of the monograph edited by Shaw and Hameedi: ". . . it appears that no ecologically or socially significant biological change has occurred that can be related to the ballast discharge."

BWT/11

In the monograph, Douglas R. Redburn, Section Chief, Water Quality Management, at the ADEC notes that accumulations of petroleum hydrocarbons above background levels in marine sediments near the ballast water outfall ". . . were, and remain, not a violation of state standards until they cause deleterious effects to aquatic life." Redburn further states that petroleum hydrocarbon accumulations near the BWT diffuser "have not been conclusively linked to any adverse changes in monitored biological populations or community structure."

In December 1988, the National Oceanic and Atmospheric Administration (NOAA) published the results of the first three years of the Pacific Coast phase of its National Benthic Surveillance Project which examined water quality effects in 31 sites in Alaska, Washington, Oregon and California. The focus of the studies was on whether chemicals could be found in the sediments and in liver tissue, biles and stomach contents of bottom fish at those sites.

Several months prior to the release of the report, in October 1988, however, the media published a story which made it appear that adverse effects were found in Port Valdez and that the BWT system was causing harm to the marine environment. A reading of the report reveals that NOAA had examined ten Alaska sites, including Port Valdez.

The sites which NOAA listed as meriting specific attention as a result of its studies were (1) Dutch Harbor (for aromatic compounds, chromium and PCBs in flathead sole); (2) Boca de Quadra near Ketchikan in Misty Fjords National Park (for sclerotic renal lesions in flathead sole and silver in sediments), and (3) Nakhu Bay near Skagway (for silver, cadmium and selenium in sediments). The studies revealed that Port Valdez was not an area of concern; it was neither included on the list nor even discussed in the text as a problem area.

Many of the contaminants NOAA tested for were not detected at all in fish from Valdez, and for those contaminants found at detectable levels, the levels were not significant at Port Valdez compared to other sites. In fact, Alaska was cited for having higher levels of water quality on the whole than the other western states tested.

Also in October 1988, Port Valdez was placed on ADEC's "List of Contaminated Waterbodies." The reason Valdez was listed, as explained in the ADEC report, related to Alyeska incidents occurring three years previously:

> "In the fall of 1985 and the spring of 1986, two additional mixing zone verification studies were conducted by Alyeska and EPA. These studies demonstrated conformance with the aromatic hydrocarbon standard at the boundary of the mixing zone in March, but found occasional violations of water quality criteria at certain depths and stations in September and October, when the water column is vertically stratified. These documented excursions are the basis for listing Port Valdez as impaired and including it on the 304(l) priority pollutant short list." ("List of Contaminated Waterbodies," p. 93.)

Most importantly, these mixing zone verification studies were conducted before the impound basins were converted into biological treatment units. The effluent from the treatment plant was much higher in September and October 1985 than in subsequent years when the biological process was working (see again Attachment 2). Alyeska has petitioned for removal of Port Valdez from the list.

B. CONCLUSIONS

In June 1990, University of Alaska IMS investigators Feder and Shaw issued their final report entitled "Environmental Studies in Port Valdez, Alaska: 1989." With regard to benthic organisms, they stated:

> "In summary, as concluded in all previous reports, all techniques used in the analysis of infaunal data in 1989 and previous years indicate that marine terminal activities in Port Valdez are not negatively affecting the benthic organisms in the deep basin or the shallow nearshore waters."

BWT/13

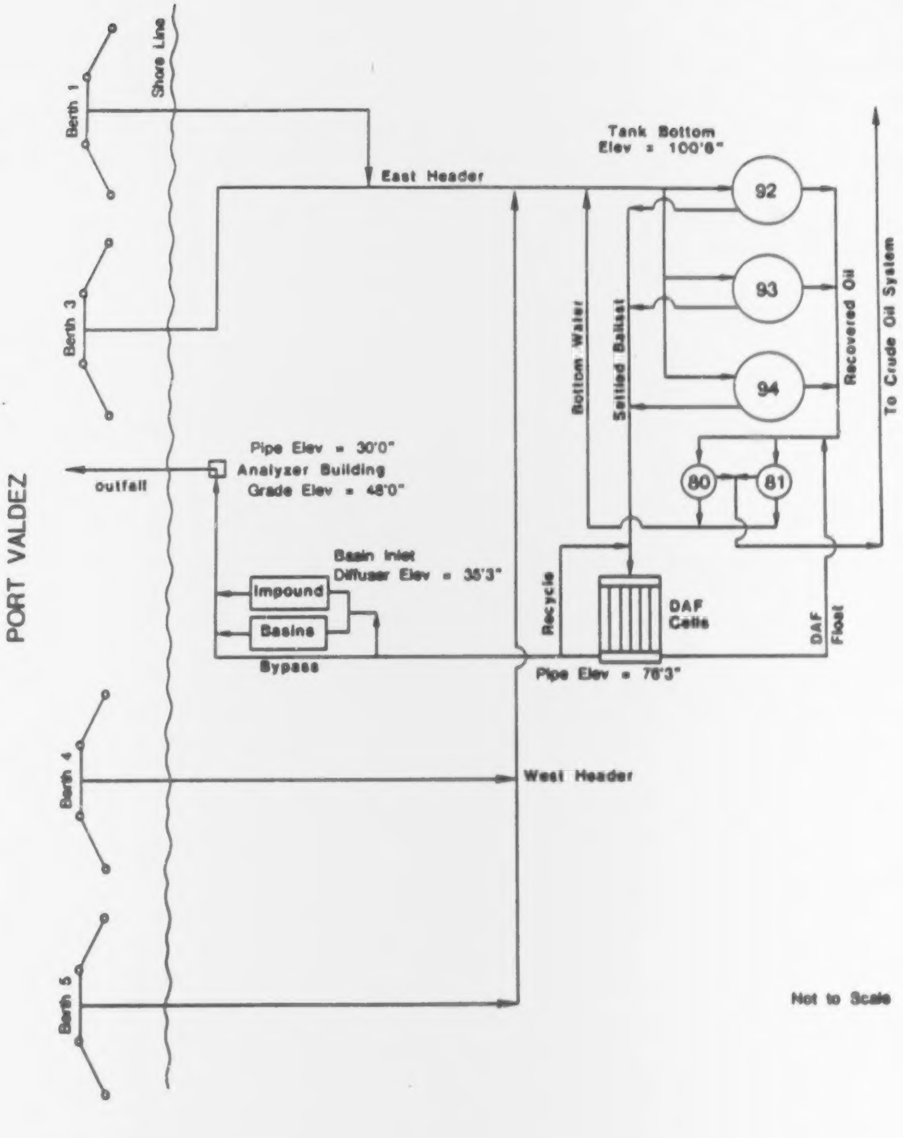
Benthic organisms are considered to be excellent indicators of environmental stress caused by petroleum hydrocarbons. These are small animals that live in the mud and are relatively stationary. Unlike a fish, for example, they are not passing through but live continuously in the same area. Thus, Alyeska has been able to monitor them for the past 12 years both in the outfall area and elsewhere in the Port of Valdez. As indicated above, it appears that no harm has come to them from BWT operations.

Recently, there has been increasing interest in toxicity studies as a measure of the effect of the effluent. Alyeska has been conducting toxicity tests for several years. The scope of the tests required in the latest NPDES permits range from assessing the effluent effects on shrimp and salmon smolt to evaluating the level of impairment of fertilization when sea urchin sperm and eggs are placed in varying concentrations of effluent. Thus, these tests measure subtle effects on very sensitive organisms.

During 1990, Alyeska had several bioassay studies performed on the BWT effluent. The effluent toxicity was so low that the consultants performing the work (Battelle Northwest and ENSR) were unable to determine any acute toxicity level at all for coonstripe shrimp or pink salmon smolt. The only tests that showed any acute toxicity were for mysid shrimp and purple sea urchins, neither of which are found in Prince William Sound. These tests indicated toxicity when the test water contained 25-30 percent BWT effluent. In reality, however, the effluent is diluted well below these concentrations in the zone of initial dilution, an area very near the outfall, used by EPA to determine compliance.

For further information, contact Corporate Affairs, Alyeska Pipeline Service Company, 1835 South Bragaw Street, Anchorage, Alaska 99512 or call (907) 265-8312.

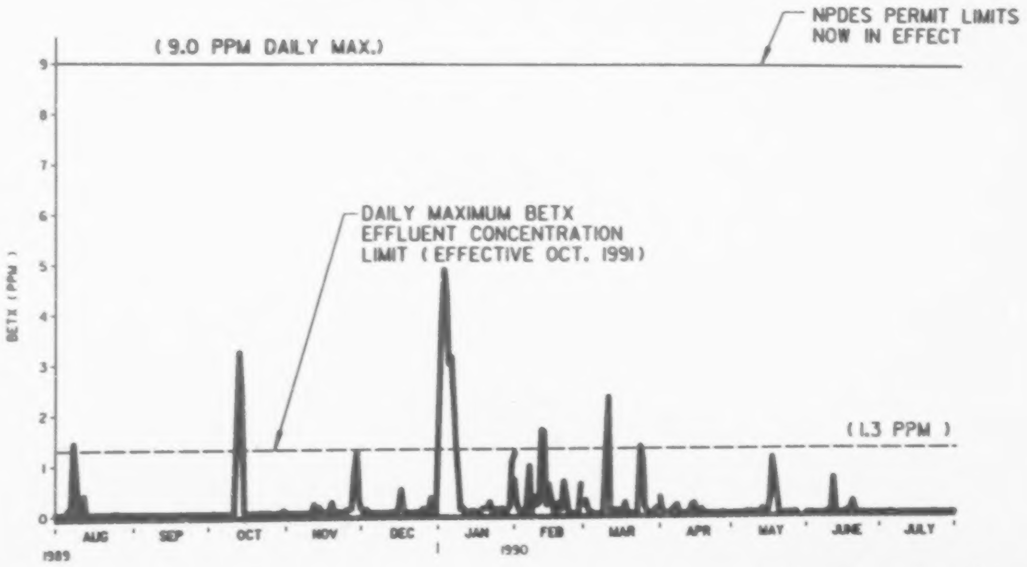
Attachment 1


Berth 1
Shore Line
East Header
Tank Bottom
Elev = 100'6"
92
93
94
Recovered Oil
To Crude Oil System
Bottom Water
Settled Ballast
Berth 3
Pipe Elev = 30'0"
Analyzer Building
Grade Elev = 48'0"
outfall
PORT VALDEZ
80
81
Basin Inlet
Diffuser Elev = 35'3"
Impound
Basins
Bypass
Recycle
DAF
Cells
DAF
Float
Pipe Elev = 76'3"
Berth 4
West Header
Berth 5
Not to Scale

General Schematic - Ballast Water Treatment Facility

Attachment 2
Page 1 of 2

BETX FINAL EFFLUENT DAILY VALUES

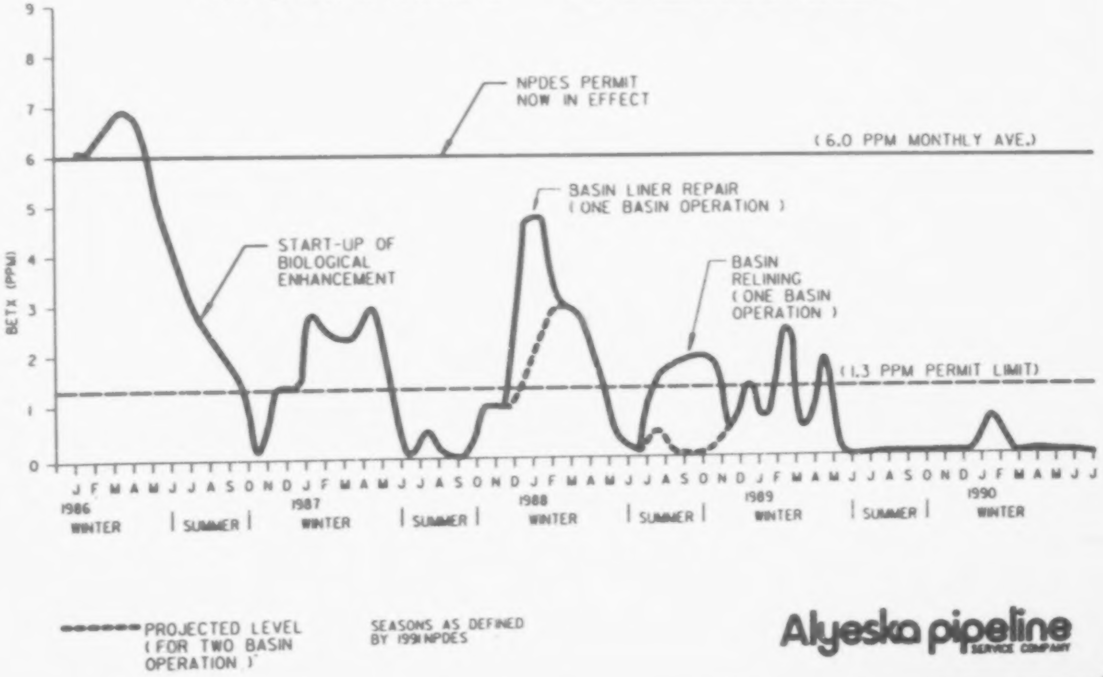


Alyeska pipeline SERVICE COMPANY

REVISED 8/[illegible]/90

Attachment 2
Page 2 of 2

BETX
FINAL EFFLUENT
MONTHLY AVERAGES



REVISED 8/31/90

Attachment 3

BALLAST WATER TREATMENT PLANT

	SULLOM VOE	VALDEZ
Design Throughput	3000 m^3/ hr	5000 m^3/hr
Max oil and grease limits (Actual)	15 ppm av/25 ppm max (actual av. 4.65 ppm	8 ppm av/10 ppm max (actual 3.51 ppm)
Total suspended solid limit	No regulations	30 ppm average (actual av. 16.78 ppm)
BTX limits	No regulations	6 ppm av., Old permit 1.3 ppm max. New permit effective 10/91 (actual av. 0.60 ppm)
Total organic compound units	No regulations	15 ppm av/25 ppm max (actual av 6.81 ppm)

ATTACHMENT 2

FINAL REPORT

ENVIRONMENTAL STUDIES IN PORT VALDEZ, ALASKA: 1990

Co-Principal Investigators:

H. M. Feder and D. G. Shaw

Institute of Marine Science
School of Fisheries and Ocean Sciences
University of Alaska Fairbanks
Fairbanks, Alaska 99775-1080

Submitted to
Alyeska Pipeline Service Company
Anchorage, Alaska

April 1991

EXECUTIVE SUMMARY

This report assesses (1) hydrocarbon concentrations in the intertidal mussel *Mytilus edulis* in June and October 1990; (2) the hydrocarbon concentrations in subtidal sediments collected in August 1990; and (3) the community structure of subtidal benthic infauna in August 1990 in Port Valdez, Alaska. The studies were designed to investigate the environmental consequences of the treated ballast water discharge at the marine terminal of the Trans Alaska Pipeline System in Port Valdez.

The concentrations of alkane and aromatic hydrocarbons were determined in triplicate for sediments collected at fourteen stations in August 1990 and in mussels (*Mytilus edulis*) collected from three intertidal sites in June and October 1990. The concentrations of individual hydrocarbons were generally in the µg/kg (parts per billion) range or less. The relative abundances of hydrocarbons indicate that marine algae, land plants and petroleum each contribute to the environmental hydrocarbons of Port Valdez.

These sediment results were compared with measurements made by the same method in 1987 and 1989 using a two-way analysis of variance (year by station) for each hydrocarbon determined. While numerous significant increases as well as decreases were observed, this analysis does not show a broad increase in most individual compounds at any station. This suggests that petroleum is not increasing in concentration in the sediments of Port Valdez. A similar analysis was applied to the four sampling times for mussels at each of three sites. Again, no trend of increasing hydrocarbons is observed.

Eight samples of tarry material obtained from 20 L sediment grab sampoles taken for biological studies were analyzed for hydrocarbons. These analyses showed the material to be moderately weathered petroleum. While the chemical data are insufficient to establish the source of the material, the spatial distribution suggests that it is associated with terminal operations.

Infaunal community structure was determined for 16 stations. The stations included Mixing-Zone and Near-Field stations near the depth of the discharge (about 70 m), Mixing-Zone stations in deeper water (to 230 m) and Far-Field stations (200-245 m).

Fluctuations, some extensive, in number of taxa (T), abundance (A), and biomass (B) of infauna occurred between 1971-90. Although the reasons for these changes are complex and are not known with certainty, some probable contributing factors are identified. Changes in A between 1971-82 appeared to reflect physical disturbance on the bottom during this period. Decreases in A and T in 1985 may have been related to higher than normal water temperatures that resulted in high larval mortality, reflected by the low numbers of benthic organisms in 1985. A general increase in TAB was observed in 1987 at all stations. Surplus carbon on the bottom resulting from decreased abundance of benthic-feeding organisms in 1985 may have increased survival of a successful year class in 1986 (sampled in 1987). Enhanced primary production and/or bottom disturbance in 1986 may have also contributed to the successful year class of 1986.

There is no evidence that hydrocarbon discharge from the diffuser had any influence on the changes of the fauna within the Port from 1971-87. Typically, changes in faunal composition and abundance during these years were similar at stations at all depths in and out of the Mixing Zone.

TAB generally decreased in 1989 within the Deep Basin, inclusive of Far-Field and Mixing-Zone stations. However, shallow Mixing-Zone stations in 1989 generally showed increases in TAB while shallow Near-Field stations demonstrated decreases in these three parameters. Depletion of carbon in the Deep-Basin in 1986-88, as a result of feeding activities of the successful 1986 benthic recruits and their continued utilization of food through 1988, may have decreased chances for survival of benthic recruits there in 1988. Lowered TAB for the benthos at some stations in 1989 appeared to reflect depleted organic carbon on the bottom. Since lowered TAB occurred at Far-Field as well as deep Mixing-Zone stations, it is unlikely that hydrocarbons derived from the diffuser could be responsible for Deep-Basin changes in 1989. The increase in TAB at shallow Mixing-Zone stations in 1989 appeared to reflect a supplemental carbon source to the benthos in this region. It is possible that the source of this carbon was bacteria derived from the biological treatment system (initiated in 1986) that entered the receiving waters by way of the diffuser. The benthic fauna within the shallow Mixing Zone did not show characteristics that typify a stressed system. In fact, the fauna appeared to be responding positively to a supplemental carbon source. On the other hand, the decrease of TAB noted at the two shallow Near-Field stations in 1989 suggested that conditions and responses of the benthic fauna were similar to those noted for the carbon-poor Deep-Basin stations. The benthic fauna at these two Near-Field stations did show characteristics of a disturbed environment. The disturbance at these stations was attributed to their location within a region subject to sediment slumping.

TAB (Taxa, Abundance, Biomass) values typically increased at Deep-Basin stations in 1990, inclusive of Far-Field, deep Mixing-Zone, and intermediate Mixing-

Zone stations. However, the shallow Mixing-Zone stations and Near-Field (shallow) Stations 80 (upstream from the diffuser) and 82 (downstream from the diffuser) in 1990 generally demonstrated decreases in TAB. The observations of changes in TAB at deep and shallow stations in 1990 are the reverse of the observations for these parameters at the same stations in 1989. Increases in TAB at the Deep-Basin stations suggest that recruits to the bottom in 1990 were utilizing carbon that had accumulated on the bottom during 1988 and 1989 when benthic abundance was low. Thus, recruits to the Deep Basin had a surplus of carbon available to them; consequently, a high percentage of them were able to survive. The decrease in TAB in 1990 at shallow Mixing-Zone stations and Near-Field Stations 80 and 82 suggests that the benthic fauna was carbon limited. It is suggested that depletion of carbon may have resulted from the intensive feeding activities of the highly successful benthos at these stations in 1988 and 1989. The resulting carbon depletion on the shallow shelf probably decreased chances for survival of benthic recruits to the bottom in 1990. Since lowered TAB occurred at Near- Field Stations 80 (upstream from the diffuser) and 82 (downstream from the diffuser), as well as shallow Mixing-Zone stations, it is unlikely that hydrocarbons derived from the diffuser were responsible for shallow-shelf changes in 1990 (with the possible exception of Station D33).

It is evident, based on assessment of data from 1971-1990, that abundance values of benthic populations in the Deep Basin and on the shallow shelf fluctuate from high to low values every two to three years. This cyclic pattern appears to support the idea of a "feast and famine" benthic regime driven by widely fluctuating carbon availability to the benthos. Thus, the long-term cyclic changes in abundance of benthic populations within the port appear to be principally a function of carbon availability and not a result of impact by hydrocarbons discharged from the diffuser.

The small amounts of weathered petroleum found in benthic samples at five stations were not associated with unusual disturbance patterns for the benthos at these locations, with the exception of D33 (adjacent to the diffuser). In fact, disturbance within the Mixing Zone appears to be randomly distributed at stations, with no particular relationship to proximity to the diffuser or presence of oil in laboratory samples. However, it does appear that the moderate disturbance noted for Station D33 (adjacent to the diffuser) may be related to diffuser output. It has been obvious since D33 was first occupied in 1987 that its fauna was influenced by its proximity to the diffuser. In 1987 and 1989, some positive responses of the benthic fauna at Station D33 to slight carbon enrichment appeared possible. This year at

Station D33, a number of parameters suggest that the fauna may be negatively affected by diffuser output. However, the observed disturbance at this station is a minor one, and the faunal picture does not reflect a seriously impacted environment. Station D33 is adjacent to a diffuser discharging large volumes of effluent from the ballast-water treatment plant, and it would indeed be surprising if no effects on the fauna resulted from the proximity of this station to the diffuser. Based on cyclic temporal changes observed at stations within the Port, it is to be expected that the fauna at Station D33 will recover to pre-1990 conditions when the other shallow Mixing-Zone stations return to higher TAB levels.

In summary, as concluded in all previous reports (e.g., Feder and Shaw, 1986, 1988, and 1990), all techniques used in the analyses of infaunal data from 1971-1990 indicate that once construction activities were completed, marine terminal activities did not affect the organisms in the Deep Basin (Far-Field and Mixing-Zone stations), the intermediate depth Mixing-Zone station, and Near-Field and shallow Mixing-Zone stations (with the possible exception of Station D33).

ATTACHMENT 3

PORT VALDEZ ENVIRONMENTAL MONITORING STUDIES

Hood, D. W. Baseline Data Survey for Valdez Pipeline Terminal Environmental Data Study, December 1969. Report No. R69-17. Institute of Marine Science, University of Alaska, Fairbanks, AK. (file: B-9.02)

Hood, D. W., et.al. Environmental Studies of Port Valdez, July 1973. Institute of Marine Science, Occasional Publication No. 3. Institute of Marine Science, University of Alaska, Fairbanks, AK. (file: B-9.02)

Hood, D. W., et.al. Data Volume One, Environmental Studies of Port Valdez, July 1973. Institute of Marine Science, Occasional Publication No. 3. Institute of Marine Science, University of Alaska, Fairbanks, AK. (file: B-9.02)

Colonell, J. M. Final Report, Continuing Environmental Studies of Port Valdez, Alaska, 1976-1979, Chapters 1-7. 1 May, 1979. Report No. R79-2. Institute of Marine Science, University of Alaska, Fairbanks, AK. (File: B-9.02)

Colonell, J. M. Final Report, Continuing Environmental Studies of Port Valdez, Alaska, 1976-1979, Chapters 8-10. 1 May, 1979. Report No. R79-2. Institute of Marine Science, University of Alaska, Fairbanks, AK. (File: B-9.02)

Colonell, J. M. Port Valdez, Alaska: Environmental Studies 1976-1979, December 1980. Occasional Publication No. 5. Institute of Marine Science, University of Alaska, Fairbanks. (File: B-9.02)

Feder, H. M. et. al. Final Report, Environmental Studies in Port Valdez, Alaska 1980-1982. Reporting Period, 1 January 1980 through 31 March 1983. Institute of Marine Science, University of Alaska, Fairbanks. (File: B-9.02)

Feder, H. M. et.al. Supplemental Report, Environmental Studies in Port Valdez, Alaska 1980-1982. Reporting Period, 1 January, 1980 through 31 March, 1983. Institute of Marine Science, University of Alaska, Fairbanks. (File: B-9.02)

Feder, H. M. et. al. Data Supplement, Final Report, Environmental Studies in Port Valdez, Alaska 1980-1982. Reporting Period, 1 January 1980 through 31 March 1983. Institute of Marine Science, University of Alaska, Fairbanks. (File: B-9.02)

Feder, H. M. & D. G. Shaw Final Report, Environmental Studies in Port Valdez, Alaska, 1985, Reporting Period, 1 September, 1985 through 15 June, 1986. Institute of Marine Science, University of Alaska, Fairbanks. (File: B-9.02)

Feder, H. M. & D. G. Shaw Final Report, Environmental Studies in Port Valdez, Alaska, 1987, July 1988. Institute of Marine Science, University of Alaska, Fairbanks. (File: B-9.02)

Shaw, D. G. Supplemental Hydrocarbon Studies in Port Valdez, Alaska 1981-1987, June 1988. Institute of Marine Science, University of Alaska, Fairbanks. (File: B-9.02)

Feder, H. M. Annual Report, A long-Term Intertidal Monitoring Program for Port Valdez, Alaska 1988-1989, May 1989. Institute of Marine Science, University of Alaska, Fairbanks. (B-9.02)

Shaw, D. G. & B. E. Bergeron Hydrocarbons in Blue Mussels of Port Valde, Alaska, August 1988 and January 1989, October 1989. Institute of Marine Science, University of Alaska, Fairbanks. (File: B-9.02)

PORT VALDEZ MONITORING AND EFFLUENT TOXICITY STUDIES

1990

Antrim, L. D. et. al., Results of effluent Toxicity Tests Conducted For Alyeska Pipeline Service Company, April 1990. Battelle/Marine Sciences Laboratory, Sequim, WA. (File: B-9.09) To agencies 4/25/90

Drottar, K. R., Acute Toxicity of Alyeska Pipeline Service Company Ballast Water Treatment Plant Effluent to Pink Salmon (Oncorhynchus gorbuscha) Under Static Renewal Conditions, May 26, 1990. ENSR Consulting and Engineering, Fort Collins Environmental Toxicology Laboratory, Fort Collins CO. (File: B-9.09) To agencies 6/27/90

Drottar, K. R., Acute Toxicity of Alyeska Pipeline Service Company Ballast Water Treatment Plant Effluent to Pink Salmon (Oncorhynchus gorbuscha) Under Flow-Through Conditions, May 26, 1990. ENSR Consulting and Engineering, Fort Collins Environmental Toxicology Laboratory, Fort Collins CO. (File: B-9.09) To agencies 6/27/90

Drottar, K. R., Acute Toxicity of Alyeska Pipeline Service Company Ballast Water Treatment Plant Effluent to Coonstripe Shrimp (Pandalus hypsinotus) Under Static Renewal Conditions, May 26, 1990. ENSR Consulting and Engineering, Fort Collins Environmental Toxicology Laboratory, Fort Collins CO. (File: B-9.09) To agencies 6/27/90

Drottar, K. R., Acute Toxicity of Alyeska Pipeline Service Company Ballast Water Treatment Plant Effluent to Coonstripe Shrimp (Pandalus hypsinotus) Under Flow-Through Conditions, May 26, 1990. ENSR Consulting and Engineering, Fort Collins Environmental Toxicology Laboratory, Fort Collins CO. (File: B-9.09) To agencies 6/27/90

Feder, H. M. & D. G. Shaw, Final Report, Environmental Studies in Port Valdez, Alaska: 1989, June 1990. Institute of Marine Science, School of Fisheries and Ocean Sciences, University of Alaska Fairbanks, Fairbanks, AK. (File: B-9.02) To agencies 6/27/90

Drottar, K. R., Acute Toxicity of Alyeska Pipeline Service Company Ballast Water Treatment Plant Effluent to Pink Salmon (Oncorhynchus gorbuscha) Under Flow-Through Conditions, June 6, 1990. ENSR Consulting and Engineering, Fort Collins Environmental Toxicology Laboratory, Fort Collins, CO. (File: B-9.09) To agencies 7/16/90

Drottar, K. R., Acute Toxicity of Alyeska Pipeline Service Company Ballast Water Treatment Plant Effluent to Pink Salmon (Oncorhynchus gorbuscha) Under Static Renewal Conditions, June 6, 1990. ENSR Consulting and Engineering, Fort Collins Environmental Toxicology Laboratory, Fort Collins, CO. (File: B-9.09) To agencies 7/16/90

Drottar, K. R., Acute Toxicity of Alyeska Pipeline Service Company Ballast Water Treatment Plant Effluent to Coonstripe Shrimp (Pandalus hypsinotus) Under Flow-Through Conditions, June 13, 1990. ENSR Consulting and Engineering, Fort Collins Environmental Toxicology Laboratory, Fort Collins, CO. (File: B-9.09) To agencies 7/16/90

Drottar, K. R., Acute Toxicity of Alyeska Pipeline Service Company Ballast Water Treatment Plant Effluent to Coonstripe Shrimp (Pandalus hypsinotus) Under Static Renewal Conditions, June 13, 1990. ENSR Consulting and Engineering, Fort Collins Environmental Toxicology Laboratory, Fort Collins, CO. (File: B-9.09) To agencies 7/16/90

Drottar, K. R., Pink Salmon (Oncorhynchus gorbuscha) 28-day Survival and Growth Toxicity Test Conducted on Alyeska Pipeline Service Company Ballast Water Treatment Plant Effluent Under Flow-Through Test Conditions, June 19 1990. ENSR Consulting and Engineering, Fort Collins Environmental Toxicology Laboratory, Fort Collins, CO. (File: B-9.09) To agencies 7/16/90

Niadu, A. S. and H. M. Feder, Annual Report, *Macoma balthica* Monitoring Study at Dayville Flats, Port Valdez, June 1990. Institute of Marine Science, University of Alaska Fairbanks, Fairbanks, AK. (File: B-9.02) To agencies 8/2/90

Feder, H. M., Annual Report, A Long-Term Intertidal Monitoring for Port valdez, Alaska, 1988-1989, Component 1: Annual Abundance and Zonation Survey, July 1990. Institute of Marine Science, University of Alaska Fairbanks, Fairbanks, AK. (File: B-9.02) To agencies 8/2/90

Ward, J. A. et.al, Draft Report, Toxicological Evaluation of Sediment Samples from Port Valdez, Alaska, Using Three Species of Marine Amphipods, Alyeska Sediment Pilot Study, July 1990. Battelle/Marine Sciences Laboratory, Sequim, WA. (File: B-9.09) To agencies 7/19/90

Antrim, L. D. et. al. Draft Report: Results of Effluent Toxicity Tests Conducted for Alyeska Pipeline Service Company, May 1990, August 1990. Battelle/Marine Sciences Laboratory, Sequim, WA. (File: B-9.09) To agencies 8/9/90

Feder, H. M., Annual Report, A Long-Term Intertidal Monitoring for Port valdez, Alaska, 1988-1989, Component 1: Annual Abundance and Zonation Survey, Component 2: Survival of Mussels (*Mytilus edulis*) and Barnacles(*Semibalanus balanoides*) in Port Valdez, July 1990. Institute of Marine Science, University of Alaska Fairbanks, Fairbanks, AK. (File: B-9.02) To agencies 8/22/90

Antrim, L. D. et. al. Draft Report: Results of Effluent Toxicity Tests Conducted in July 1990 for Alyeska Pipeline Service Company, September 1990. Battelle/Marine Sciences Laboratory, Sequim WA. (File: B-9.09) To Agencies 9/17/90

Drotter, K. R., and S. J. Patti. Acute Toxicity of Alyeska Pipeline Service Company Ballast Water Treatment Plant Effluent to Mysid Shrimp (Mysidopsis bahia) Under Static Renewal Conditions, July 22, 1990. ENSR Consulting and Engineering, Fort Collins Toxicological Laboratory, Ft. Collins CO. (file B-9.02) To agencies 9/24/90

Drotter, K. R., and S. J. Patti. Acute Toxicity of Alyeska Pipeline Service Company Ballast Water Treatment Plant Effluent to the Inland Silverside (Menidia beryllina) Under Static Renewal Conditions, July 22, 1990. ENSR Consulting and Engineering, Fort Collins Toxicological Laboratory, Ft. Collins CO. (file B-9.02) To agencies 9/24/90

Drotter, K. R., and S. J. Patti. Short-Term Chronic Toxicity of Ballast Water Treatment Plant Effluent to the Inland Silverside (Menidia beryllina) Under Static Renewal Conditions, July 25, 1990. ENSR Consulting and Engineering, Fort Collins Toxicological Laboratory, Ft. Collins CO. (file B-9.02) To agencies 9/24/90

Feder, H. M., Annual Report, A Long-Term Intertidal Monitorng Program For Port Valdez, Alaska 1988-1990, October 1990. Institute of Marine Science, School of Fisheries and Marine Science, University of Alaska, Fairbanks, Fairbanks, AK. (file B-9.02) To agencies 11/26/90

Anthony, J., Group Dynamics of the Sea Otter (Enhydra Lutris) in Port Valdez, Alaska, October 1990. Institute of Marine Science, School of Fisheries and Marine Science, University of Alaska, Fairbanks, Fairbanks, AK. (file B-9.02) To agencies 11/26/90

Antrim, L. D. et. al. Draft Report: Results of Effluent Toxicity Tests Conducted in October 1990 for Alyeska Pipeline Service Company, November 1990. Battelle/Marine Sciences Laboratory, Sequim WA. (File: B-9.09) To Agencies 12/7/90

Antrim, L. D. & J. Q. Word Toxicological Evaluation of Sediment Samples from Port Valdez, Alaska, Using the Amphipod Rhepoxynius Abronius, Alyeska Sediment Study, Phase 2, January 1991. Battelle/Marine Sciences Laboratory, Sequim WA. (File B-9.09)

Ward, J. A. & J. Q. Word The Sensitivity of Two Species of Amphipods to Sediments Spiked With Weathered North Slope crude Oil, Alyeska Sediment Study, Phase 2, February 1991. Battelle/Marine Sciences Laboratory, Sequim WA. (File B-9.09)

Kinnetics Laboratories, Inc. 1989-1990 NPDES Monitoring Program Conducted by Alyeska Pipeline Service Company on Sediment Chemistry, Benthic Infauna and Sediment Toxicity, April 1991. Kinnetics Laboratories, Inc. Carlsbad, CA. (File B-9.04)

Feder, H. M. & D. G. Shaw Final Report, Environmental Studies in Port Valdez, Alaska: 1990, April 1991. Institute of Marine Science, School of Fisheries and Marine Science, University of Alaska, Fairbanks, Fairbanks, AK. (File B-9.02)

Questions by Senators Wallop and Murkowski
for Roger C. Herrera of BP Exploration (Alaska), Inc.

1) It has been alleged that there will be significant development, consisting of 280 miles of road and other infrastructure, in the potential development of ANWR? How is industry reducing the size of the so-called "footprint"? Can you describe what type of development you envision?

2) What have you learned at Prudhoe Bay that can make development of ANWR more environmentally secure?

3) Given the estimates of potential oil reserves in ANWR and the existing state of the art in oil field development, what is the industry's latest estimate of the size of the development footprint?

4) Please describe how many barrels of oil have been discovered at Prudhoe Bay due to "enhanced oil recovery."

Questions 1-3 It is very diffic
detailed nature of the surface infrastructure for new oil fields on the coastal plain of ANWR. For example, the depth of the oil reservoir below the surface determines the nature of the options, as does the thickness of the oil reservoir and its physical extent. An oil reservoir at, say, 5000 feet below the surface, usually requires more surface well gravel pads than a deeper reservoir at perhaps 10,000 feet depth. Similarly an oil column which is 1000 feet thick is usually easier to produce and requires fewer surface facilities than one which is only 100 feet thick and spread over a large area.

Nevertheless, one can say with certainty that a well pad in ANWR will be a quarter of the size, or smaller, than a similar pad in Prudhoe Bay. It will have one access road going to it rather than two. It will have no reserve pit adjacent to it. Treatment plants to process the oil, gas and water produced will be considerably smaller and more compact than those seen at Prudhoe Bay, and there will be far less, or no, duplication of facilities such as airports and base camps.

The Prudhoe Bay field which was planned in the early 1970s as the very first oil field in the arctic, covers up 5300 acres of tundra habitat. If it was developed today, given our present state of knowledge, its footprint would be less than half that number of acres. Further, the zone of influence experienced by wildlife that use the field area would now be significantly smaller because of our fuller understanding of exactly what troubles animals and birds.

One can conclude from the above that the DOI figure of 12,000 acres that is estimated will be used for development of the coastal plain is probably a gross overestimation.

If the best case scenario of ANWR oil reserves proves to be correct, and if the oil is contained in one discrete oil field approximately the size of Prudhoe Bay, it is quite reasonable to expect the "Footprint" to be about 2000 acres. However, if the same amount of oil is divided between three or four fields discovered over a period of perhaps five or six years, the amount of gravel used would inevitably increase and a total of 4000 acres might be a reasonable high end estimate.

The footprint would be made up of an east-west access road, well pads, utility pads, one airstrip, basecamp, a small dock facility, gravel pit/water reservoir, access roads, seawater plant and oil treatment facilities. The footprint of pipelines will be minor because all pipelines will be constructed in the winter time from ice roads which will disappear in the following spring. The zone of influence of pipelines will also be less than at Prudhoe because all will be constructed at least 5 feet above ground level.

A major change between the infrastructure at Prudhoe Bay and a future development on the coastal plain of ANWR will be in waste handling techniques. Drilling wastes will all be injected into approved zones. Other wastes will be recycled for reuse or shipped out of the area for approved disposal. Open waste pits or reserve pits will not be used, and also, to the extent possible, most facilities will be designed for aesthetic considerations as well as practical ones.

One can, with confidence, predict that a new coastal plain development will be quite different and orders of magnitude more benign than the historic Prudhoe type development, good though that has been.

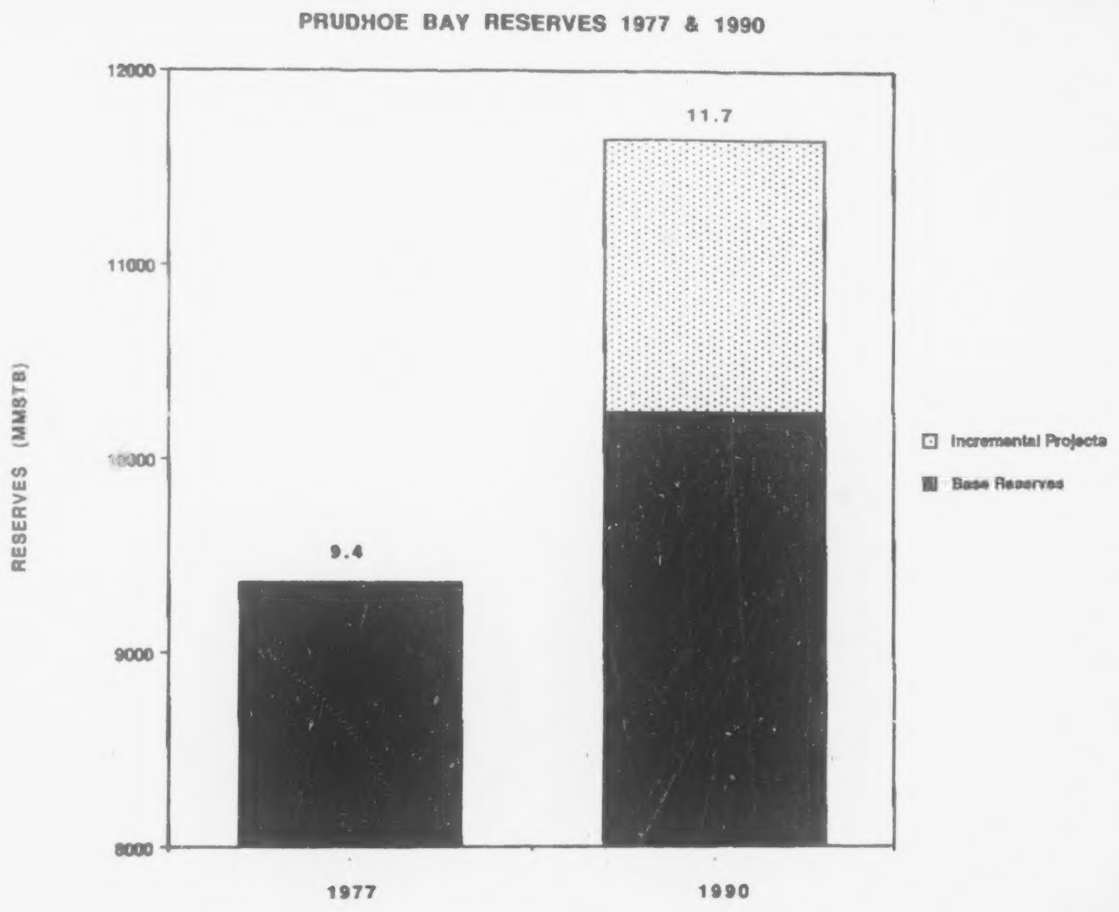
PRUDHOE BAY RESERVES COMPARISON 1977 AND 1990

Base Reserves

Includes primary and waterflood recovery and condensates.
- Development drilling

Incremental Projects

Includes all proved and non-proved booked reserves other than base.
- Vaporization: All gas handling expansions (GHX-1 & 2) - 477 MMstb
- Enhanced Oil Recovery Projects (PBMGP) - 396 MMstb
- Natural Gas Liquids - 533 MMstb


PRUDHOE BAY RESERVES 1977 & 1990
RESERVES (MMSTB)
12000
11000
10000
9000
8000
9.4
11.7
1977
1990
⊡ Incremental Projects
▨ Base Reserves

Appendix II—Additional Material Submitted for the Record

THE WILDLIFE SOCIETY
ALASKA CHAPTER

6 March 1991

Honorable J. Bennett Johnston, Chairman
Senate Energy and Natural Resources Committee
Room SD-364, Dirksen Building
Washington, DC 20510

Dear Senator Johnston:

The Alaska Chapter of The Wildlife Society is a nonprofit organization of biologists, researchers, managers, educators, conservation officers, and administrators dedicated to the stewardship of wildlife and their habitats. We are a society of professionals whose membership includes those employed by government agencies, universities, and the private sector.

My purpose in writing is to bring our position statement (enclosed) on oil exploration and development in the Arctic National Wildlife Refuge (ANWR) to your attention. Further I request that my letter and our position statement become an official part of the hearing record for S.B. 341.

Please note that we are not antidevelopment, and that our statement offers potential mitigation measures to lessen effects on our unique wildlife resources should oil development occur. We are convinced, however, that claims that proposed oil development can proceed without damage to populations of caribou, muskoxen and other wildlife are premature in light of current scientific evidence. We believe the risk to wildlife from oil development potentially is great, and that special consideration is necessary in proposing developments in fragile arctic ecosystems.

We hope our position statement will be useful in understanding wildlife issues that will accompany proposed oil development in ANWR, and that this information may help place ANWR and its importance to wildlife in a proper perspective in developing our national energy policy.

Thank you for your time and consideration of this issue.

Sincerely,

R. Terry Bowyer, President
Alaska Chapter of The Wildlife Society
310 Irving Building
University of Alaska Fairbanks
Fairbanks, AK 99775

THE WILDLIFE SOCIETY
ALASKA CHAPTER

POSITION STATEMENT OF THE ALASKA CHAPTER OF THE WILDLIFE SOCIETY ON THE ARCTIC NATIONAL WILDLIFE REFUGE

The Arctic National Wildlife Range (now Refuge; ANWR) was established in 1960 to protect wildlife and wilderness values for human use. In 1980 Congress enlarged the Refuge to almost 19 million acres, expanded the Refuge purposes, and designated 8 million acres of mountain terrain as Wilderness. At the same time Congress required of the Secretary of the Interior an assessment of petroleum and wildlife values of the Refuge's 1.5-million-acre Arctic Coastal Plain (or "1002 Area") and reserved to itself the decision whether to allow oil and gas leasing and extraction within that area. The assessments are complete and the Secretary of Interior has recommended leasing of the entire 1002 Area on the grounds that the chance of discovering very large oil reserves outweighs the unavoidable risks to fish and wildlife habitat and populations.

Bills have been filed in Congress to open the Coastal Plain to leasing as recommended by the Secretary, but public sentiment is sharply divided on this issue. Counter measures have been filed to designate the entire area as Wilderness closed to leasing. Opposition to exploration and development stems from concerns about the integrity of ANWR as Wilderness, and opposition to leasing of the entire 1002 Area stems from concerns about impact of development on wildlife. This position paper deals only with the latter issue.

The impacts of oil and gas development on fish and wildlife are dependent on the timing, extent, location, intensity, and carefulness of petroleum exploration, development, and extraction activities. With present knowledge of the fish and wildlife resources of ANWR and of the functioning of arctic ecosystems, primary biological concerns under the petroleum extraction scenarios presented by the Department of Interior include:

1. The well-being of the Porcupine Caribou Herd, now numbering about 200,000, which in most years calves and seeks relief from insect harassment on the Coastal Plain of the Refuge, especially the 1002 Area, migrates throughout ANWR, and winters in Yukon Territory and northeastern Alaska, including South Slope portions of ANWR;

2. The well-being of muskoxen, reintroduced to ANWR in 1969, which now number approximately 600 on the North Slope, are rapidly expanding their population size and distribution, and a majority of which depend on riparian and adjacent upland habitats in the 1002 Area;

3. The well-being of polar bear, brown bear, wolverine, and other species of which numbers have declined following development in other areas;

4. The effects of disturbance on up to 325,000 snow geese that breed in Canada and obtain energy for fall migrations while feeding in late summer in the Foothills and Coastal Plain of ANWR and adjacent Yukon Territory;

5. The effects of displacement of wildlife from the 1002 Area through increased human activities and community development on human uses of wildlife;

6. Dewatering of streams and lakes due to demand for large quantitites of water during exploratory and production drilling and oil extraction operations;

7. Loss of scarce fish overwintering areas, maintained by year-round springs, through winter water withdrawal, gravel extraction, road and pipeline construction, and other activities;

8. Loss and alteration of riparian shrub communities that are productive and often critical habitats for birds and mammals such as muskoxen;

9. Disruption of nearshore marine and brackish water ecosystems through use of causeways, drill pads, freshwater withdrawal, and other petroleum-related facilities;

10. Releases of toxic materials into wetlands, waterways, and the atmosphere from drill-mud disposal pits, camps, oil spills, and other sources;

11. The potential for localized overharvest of fish and wildlife due to facilitation of human access; and

12. The unknown, long-term, and cumulative effects of circumpolar arctic development on the arctic environment.

If oil is sought, found, and extracted in the Arctic National Wildlife Refuge some losses of wildlife habitat and populations are inevitable. Although experience at Prudhoe Bay and other arctic areas provides some basis for guiding development, present knowledge of fish and wildlife resources in ANWR is inadequate for generation of thorough recommendations to minimize impact of full-scale petroleum development. For example, the relationships of Porcupine caribou with their calving and summer habitats on the Coastal Plain are not well understood. Similarly, we have little understanding of the potential effects of disturbance on migratory geese, or of the effects of human activities on the movements and habitat use of muskoxen.

Human interests in the well-being of ANWR wildlife are best served at this time by excluding development activities entirely, or by limiting development until additional knowledge is obtained. Congress can exclude all development by designation of the entire 1002 Area as Wilderness or by taking no further action to open the 1002 Area to such development at this time. The "no action" alternative would allow further review and wildlife research prior to a permanent decision.

If Congress decides against total exclusion of petroleum activities from the Refuge, it and executive agencies can take steps to minimize short- and long-term fish and wildlife habitat losses. In this case, we recommend the following:

1. Congressional designation of approximately 600,000 acres of the southeast portion of the Coastal Plain (Fig. 1) and the proposed Sadlerochit Spring Special Area as an area with no development for petroleum at this time; this will protect most of the calving grounds of the Porcupine Caribou Herd, important muskox habitat, preferred snow goose staging areas, and sensitive streams and rivers until additional information is available to better guide development in this most sensitive area;

2. Congressional authorization of exploration, but not leasing, on the remainder of the 1002 Area, provided that appropriate mitigation measures are implemented to minimize disturbance to caribou, muskoxen, snow geese, and other wildlife; if exploration reveals recoverable oil reserves, Congressional authorization of leasing in certain areas and under such conditions to minimize impacts based on results of research during exploration;

3. Congressional commitment of adequate resources for research on caribou, muskoxen, snow geese, and other species to assess impacts and develop refined mitigation measures;

4. Implementation of a strict policy of minimal road and facility development incorporating adequate setbacks from lakes, streams, and marine nearshore environment adjacent to the Refuge to mininize adverse effects on these important habitats;

5. Appointment by Congress of a special commission composed of experienced, knowledgeable professionals in the fields of wildlife, fisheries, geology, petroleum development, and environmental design to provide policy-level guidance to Congress for general measures to protect fish and wildlife resources during oil and gas exploration and development, to oversee additional predevelopment research needs and review the results and conclusions from this research in order to apply such conclusions to mitigation measures during development, and to provide recommendations on long-term monitoring of industrial impacts on key fish and wildlife species and critical aspects of their environments;

6. Establishment of a joint federal/state organization with representation from appropriate agencies for preparation and implementation of appropriate regulations and other mitigation measures to protect fish and wildlife habitats and populations during project design and construction, and to provide day-to-day oversight of development activities in the field; and

7. Establishment of a procedure, with adequate funding, for removal of all development-related facilities and habitat rehabilitation after oil extraction is completed.

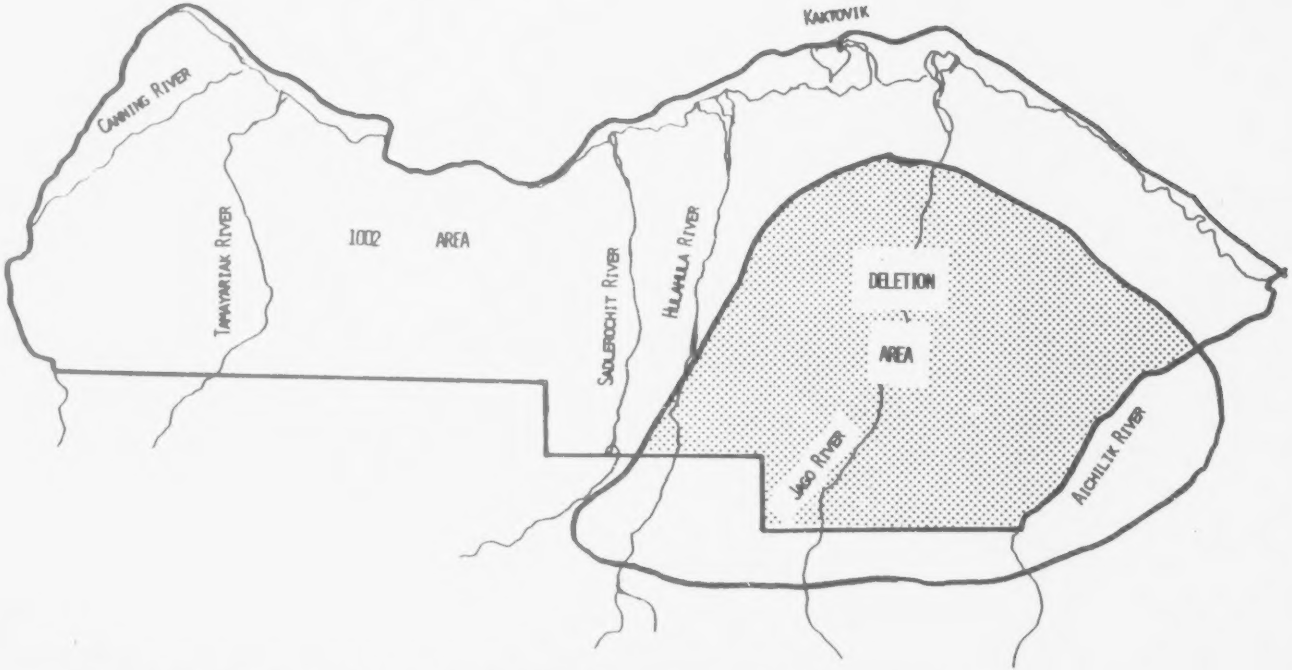

KAKTOVIK
CANNING RIVER
TAMAYARIAK RIVER
1002 AREA
SADLEROCHIT RIVER
HULAHULA RIVER
DELETION AREA
JAGO RIVER
AICHILIK RIVER

Figure 1. "1002 Area" of Arctic National Wildlife Refuge. Shaded portion recommended for deletion from exploration and development at this time.

national grange

1616 H STREET, N.W. WASHINGTON, D.C. 20006 (202) 628-3507

Robert E. Barrow, Master

1991 MAR 13 AM 10:54

1991 MAR 13 AM 10:54

March 12, 1991

The Honorable J. Bennett Johnston, Chairman
Senate Committee on Energy and Natural Resources
364 Dirksen Senate Office Building
Washington, D.C. 20510-6150

Dear Mr. Chairman:

On March 12th, the Senate Committee on Energy and Natural Resources will hold a hearing to consider S. 341, the National Energy Security Act of 1991. Title IX of this bill would authorize development of the petroleum resources of the Coastal Plain region of the Arctic National Wildlife Refuge in Alaska. Last November, the delegates to the National Grange's 124th Annual Convention adopted the following policy on this issue:

> "The National Grange urges the United States Congress to adopt the recommendations of the United States Fish and Wildlife Service, the Secretary of Energy, and the Secretary of the Interior to approve the exploration and production of oil reserves on the Coastal Plain of the Arctic National Wildlife Refuge in accordance with the terms of an environmentally sound development plan."

The availability and security of the United States' energy supplies are issues that are of great concern to U.S. farmers and rural residents. Petroleum products, both directly and indirectly, constitute one of the highest production costs on modern farms. Hundreds of thousands of family farmers must rely upon the uninterrupted availability of petroleum products in order to be able to meet nature's uncompromising cycles that dictate planting and harvesting schedules. Overall, rural residents pay a higher percentage of their disposable income for petroleum energy products than urban residents due to higher transportation and heating/air conditioning costs.

In recent months, the United States has imported over 50% of its crude oil supply. Over an extended period of time, this heavy reliance on foreign oil suppliers will threaten the United States' energy security. The exploration and development of the ANWR's Coastal Plain would provide a large, new, domestic petroleum supply that would help keep jobs and trade dollars in our country, thus strengthening our economy. Meanwhile our nation could reduce our dependence on foreign oil suppliers from areas of the world that are threatened by political instability.

The success of the petroleum development program at nearby Prudhoe Bay shows that similar development in the ANWR can be accomplished with minimal impact on the environment. The current drilling and construction techniques that are being used in the Arctic leave the surrounding tundra unspoiled. Wildlife species, such as caribou, are heavily shielded from contact with man and are thriving in the vicinity of the oil operations. The release of all materials into the environment from all aspects of oil production in the Arctic is extensively monitored and meets all of the federal, state and local governments' standards.

If environmental concerns are properly heeded, the Grange believes that ANWR development can be a part of a comprehensive, national, energy policy. Other aspects of that policy must include increased conservation, more efficient use of traditional domestic energy resources, and greater reliance on alternative energy sources, such as ethanol fuels. The National Grange believes that the Senate Committee on Energy and Natural Resources should move without delay to report favorably on S. 341, or similar legislation, to establish a comprehensive national energy plan that includes development of the petroleum resources of the Coastal Plain of the Arctic National Wildlife Refuge in an environmentally sound manner.

Thank you for the opportunity to inform you about Grange policy. I would appreciate this letter being made part of the official hearing record. In addition, I would be interested in receiving any views that you or any member of the Committee might have on this issue.

Sincerely,

Robert E. Barrow
National Master

REB/lwh

THE WILDLIFE SOCIETY
5410 Grosvenor Lane • Bethesda, MD 20814-2197
Tel: (301) 897-9770 • Fax: (301) 530-2471

19 March 1991

The Honorable J. Bennett Johnston, Chairman
Subcommittee on Energy and Water Development
SD-132 Dirksen Senate Office Building
Washington, DC 20510

Dear Senator Johnston:

The Wildlife Society appreciates this opportunity to comment on S. 341, Title IX, which proposes to open the Arctic National Wildlife Refuge coastal plain to oil and gas leasing and development. The Wildlife Society is the educational and scientific association of over 8,900 wildlife managers, researchers, educators, and administrators working in the public and private sectors to promote wise stewardship of natural resources. The Wildlife Society provides objective, scientific viewpoints on wildlife and natural resource issues.

The Alaska Chapter of The Wildlife Society, representing wildlife professionals in Alaska, has prepared a position statement on the development of the Arctic National Wildlife Refuge. The Alaska Chapter's position has been adopted as an international policy of The Wildlife Society. The complete position statement is attached for the record.

Wildlife interests in the Arctic National Wildlife Refuge are best served at this time by excluding development entirely or by limiting development until additional knowledge is obtained. If Congress decides against total exclusion of petroleum activities from ANWR, The Wildlife Society urges that the following recommendations to minimize fish and wildlife habitat losses be incorporated into any legislation proposing to open the Refuge:

1) Designate approximately 600,000 acres of the southeast portion of the coastal plain and the Sadlerochit Spring area as areas with no oil development at this time;

2) Explore, prior to leasing, the remainder of the 1002 area. If exploration reveals recoverable reserves, leasing may be permitted in certain areas and under such conditions to minimize impacts based on the results of research during exploration;

3) Appoint a special Congressional commission to provide

policy-level guidance on mitigation, research needs, and monitoring;

4) Establish a joint federal/state organization to prepare and implement regulations and mitigation measures that protect fish and wildlife and to oversee field activities;

5) Establish and fund a procedure for removing all development-related facilities and rehabilitating habitat after oil extraction is completed.

Leasing and development of the Arctic National Wildlife Refuge coastal plain could result in the destruction of critical habitat for sensitive wildlife. The proposed "National Energy Security Act of 1991" (S. 341) would not ensure protection of this habitat.

Thank you for your consideration. Please enter these comments in the official hearing record.

Sincerely,

Harry E. Hodgdon
Executive Director

sjp

Attachment

cc: Terry Bowyer, President, Alaska Chapter, TWS

THE WILDLIFE SOCIETY
ALASKA CHAPTER

POSITION STATEMENT
OF
THE ALASKA CHAPTER OF THE WILDLIFE SOCIETY
ON THE
ARCTIC NATIONAL WILDLIFE REFUGE

The Arctic National Wildlife Range (now Refuge; ANWR) was established in 1960 to protect wildlife and wilderness values for human use. In 1980 Congress enlarged the Refuge to almost 19 million acres, expanded the Refuge purposes, and designated 8 million acres of mountain terrain as Wilderness. At the same time Congress required of the Secretary of the Interior an assessment of petroleum and wildlife values of the Refuge's 1.5-million-acre Arctic Coastal Plain (or "1002 Area") and reserved to itself the decision whether to allow oil and gas leasing and extraction within that area. The assessments are complete and the Secretary of Interior has recommended leasing of the entire 1002 Area on the grounds that the chance of discovering very large oil reserves outweighs the unavoidable risks to fish and wildlife habitat and populations.

Bills have been filed in Congress to open the Coastal Plain to leasing as recommended by the Secretary, but public sentiment is sharply divided on this issue. Counter measures have been filed to designate the entire area as Wilderness closed to leasing. Opposition to exploration and development stems from concerns about the integrity of ANWR as Wilderness, and opposition to leasing of the entire 1002 Area stems from concerns about impact of development on wildlife. This position paper deals only with the latter issue.

The impacts of oil and gas development on fish and wildlife are dependent on the timing, extent, location, intensity, and carefulness of petroleum exploration, development, and extraction activities. With present knowledge of the fish and wildlife resources of ANWR and of the functioning of arctic ecosystems, primary biological concerns under the petroleum extraction scenarios presented by the Department of Interior include:

1. The well-being of the Porcupine Caribou Herd now numbering about 200,000, which in most years calves and seeks relief from insect harassment on the Coastal Plain of the Refuge, especially the 1002 Area, migrates throughout ANWR, and winters in Yukon Territory and northeastern Alaska, including South Slope portions of ANWR;

2. The well-being of muskoxen, reintroduced to ANWR in 1969, which now number approximately 600 on the North Slope, are rapidly expanding their population size and distribution, and a majority of which depend on riparian and adjacent upland habitats in the 1002 Area;

3. The well-being of polar bear, brown bear, wolverine, and other species of which numbers have declined following development in other areas;

4. The effects of disturbance on up to 325,000 snow geese that breed in Canada and obtain energy for fall migrations while feeding in late summer in the Foothills and Coastal Plain of ANWR and adjacent Yukon Territory;

5. The effects of displacement of wildlife from the 1002 Area through increased human activities and community development on human uses of wildlife;

6. Dewatering of streams and lakes due to demand for large quantitites of water during exploratory and production drilling and oil extraction operations;

7. Loss of scarce fish overwintering areas, maintained by year-round springs, through winter water withdrawal, gravel extraction, road and pipeline construction, and other activities;

8. Loss and alteration of riparian shrub communities that are productive and often critical habitats for birds and mammals such as muskoxen;

9. Disruption of nearshore marine and brackish water ecosystems through use of causeways, drill pads, freshwater withdrawal, and other petroleum-related facilities;

10. Releases of toxic materials into wetlands, waterways, and the atmosphere from drill-mud disposal pits, camps, oil spills, and other sources;

11. The potential for localized overharvest of fish and wildlife due to facilitation of human access; and

12. The unknown, long-term, and cumulative effects of circumpolar arctic development on the arctic environment.

If oil is sought, found, and extracted in the Arctic National Wildlife Refuge some losses of wildlife habitat and populations are inevitable. Although experience at Prudhoe Bay and other arctic areas provides some basis for guiding development, present knowledge of fish and wildlife resources in ANWR is inadequate for generation of thorough recommendations to minimize impact of full-scale petroleum development. For example, the relationships of Porcupine caribou with their calving and summer habitats on the Coastal Plain are not well understood. Similarly, we have little understanding of the potential effects of disturbance on migratory geese, or of the effects of human activities on the movements and habitat use of muskoxen.

Human interests in the well-being of ANWR wildlife are best served at this time by excluding development activities entirely, or by limiting development until additional knowledge is obtained. Congress can exclude all development by designation of the entire 1002 Area as Wilderness or by taking no further action to open the 1002 Area to such development at this time. The "no action" alternative would allow further review and wildlife research prior to a permanent decision.

If Congress decides against total exclusion of petroleum activities from the Refuge, it and executive agencies can take steps to minimize short- and long-term fish and wildlife habitat losses. In this case, we recommend the following:

1. Congressional designation of approximately 600,000 acres of the southeast portion of the Coastal Plain (Fig. 1) and the proposed Sadlerochit Spring Special Area as an area with no development for petroleum at this time; this will protect most of the calving grounds of the Porcupine Caribou Herd, important muskox habitat, preferred snow goose staging areas, and sensitive streams and rivers until additional information is available to better guide development in this most sensitive area.

2. Congressional authorization of exploration, but not leasing, on the remainder of the 1002 Area, provided that appropriate mitigation measures are implemented to minimize disturbance to caribou, muskoxen, snow geese, and other wildlife; if exploration reveals recoverable oil reserves, Congressional authorization of leasing in certain areas and under such conditions to minimize impacts based on results of research during exploration;

3. Congressional commitment of adequate resources for research on caribou, muskoxen, snow geese, and other species to assess impacts and develop refined mitigation measures;

4. Implementation of a strict policy of minimal road and facility development incorporating adequate setbacks from lakes, streams, and marine nearshore environment adjacent to the Refuge to mininize adverse effects on these important habitats;

5. Appointment by Congress of a special commission composed of experienced, knowledgeable professionals in the fields of wildlife, fisheries, geology, petroleum development, and environmental design to provide policy-level guidance to Congress for general measures to protect fish and wildlife resources during oil and gas exploration and development, to oversee additional predevelopment research needs and review the results and conclusions from this research in order to apply such conclusions to mitigation measures during development, and to provide recommendations on long-term monitoring of industrial impacts on key fish and wildlife species and critical aspects of their environments;

6. Establishment of a joint federal/state organization with representation from appropriate agencies for preparation and implementation of appropriate regulations and other mitigation measures to protect fish and wildlife habitats and populations during project design and construction, and to provide day-to-day oversight of development activities in the field; and

7. Establishment of a procedure, with adequate funding, for removal of all development-related facilities and habitat rehabilitation after oil extraction is completed.

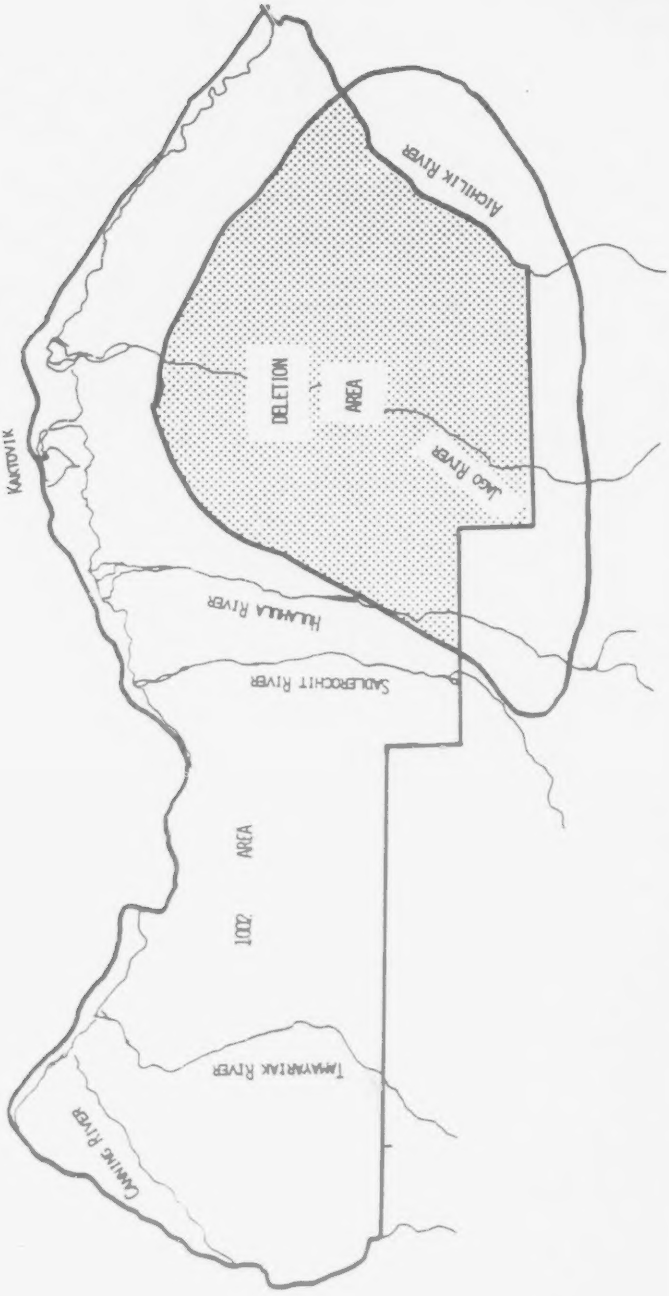

KAKTOVIK
AICHILIK RIVER
DELETION AREA
JAGO RIVER
HULAHULA RIVER
SADLEROCHIT RIVER
1002 AREA
TAMAYARIAK RIVER
CANNING RIVER

Figure 1. "1002 Area" of Arctic National Wildlife Refuge. Shaded portion recommended for deletion from exploration and development at this time.

Canadian Embassy Ambassade du Canada

501 Pennsylvania Ave., N.W.
Washington, D.C. 20001

April 15, 1991

The Honourable J. Bennett Johnston
Chairman, Senate Committee on Energy
and Natural Resources
136 Hart Senate Office Building
Washington, D.C. 20510-1802

Dear Senator Johnston,

On March 12, the Energy and Natural Resources Committee held a hearing on the proposal to open up the Arctic National Wildlife Refuge to oil and gas development. The Committee did not discuss the Canadian Government's concerns that such activities would threaten the continued viability of shared wildlife populations which migrate annually from Canada into the Refuge.

We are particularly concerned about the impact on the Porcupine Caribou Herd. Thousands of Canadian aboriginal people have depended on this herd for subsistence and cultural needs for centuries. The coastal plain of the Refuge is the calving area for this herd; this is the same area proposed for oil and gas development. We believe the best way to protect the Porcupine Caribou Herd, and other shared wildlife populations, would be for the United States to designate the 1002 area as wilderness. Canada has itself forgone oil and gas exploration without fully ascertaining the potential energy reserves in the Canadian calving area out of concern for this sensitive environment.

The attached paper details our concerns and answers some frequently raised questions about Canada's actions to protect the Porcupine Caribou Herd. I would be grateful if you could bring this letter and its attachment to the attention of other Committee members before markup. I would also request that these documents be included on the March 12 hearing record. Your assistance would be greatly appreciated.

Yours sincerely,

D.H. Burney
Ambassador

cc. Members of Senate Committee on Natural Resources

CANADIAN PERSPECTIVE
ARCTIC NATIONAL WILDLIFE REFUGE DEVELOPMENT

Canadian Concerns

- The Arctic National Wildlife Refuge (the Refuge) is home to significant shared wildlife populations which migrate annually from Canada. Of particular concern to Canada is the Porcupine Caribou Herd (PCH), which has traditionally calved in the precise area under consideration by Congress for development.

- In the long term, development activity in the sensitive calving grounds could reduce the herd's size and, in the short term, its associated infrastructure, such as pipelines, could disrupt the herd's migratory routes. This could have a devastating impact on the Canadian and Alaskan communities who have depended on this herd for subsistence and cultural survival for centuries. The best means to ensure continued protection for the herd is to designate the entire Refuge as wilderness.

Canadian Interests

- In the Alaska National Interest Lands Conservation Act of 1980 the Secretary of the Interior is instructed to consult with Canada in evaluating the impacts of development, "particularly with respect to the Porcupine Caribou Herd". In the 1987 Canada /U.S.A. Agreement on the Conservation of the Porcupine Caribou Herd, the U.S. agreed "to conserve the Porcupine Caribou Herd and its habitat" and to consult promptly in the event of significant damage to the herd or disruption of its migration routes.

Caribou and Development: the Facts

- Advocates of development argue that an increase in the size of the Central Arctic Herd (CAH) during the development of Prudhoe Bay proves caribou can co-exist with development. However, according to long-term observations of the herd by wildlife biologists, the actual productivity of the CAH, i.e. the cow:calf ratio during mid-June, has been reduced in the last 10 years by 10%, particularly among those animals associated with development.

- The real reason for the increase was that development wiped out the CAH's natural predators thereby reducing normal attrition. There is a significant risk that, in the long term, development in the Refuge will similarly affect the PCH's productivity and, absent mitigating activities, such as wiping out the PCH's natural predators, lead to a reduction in its size.

- The impact of development is likely to be more severe for the PCH than was the case for the CAH. The CAH is much smaller than the PCH, yet has a much larger area of the coastal plain in which to calve. When displaced by development, the CAH had acceptable alternative calving areas. The PCH's traditional calving area is much smaller. If displaced by development, the alternatives open to it are unsatisfactory and would expose the caribou to increased danger from predators, poor nutrition, and insect harassment.

...2

- In the CAH, during the post-calving period, groups of caribou have shown difficulty crossing roads associated with pipelines. Cows and calves, and large groups, have shown particular sensitivity. The larger the group the greater the difficulty. In the CAH a large group is 100 animals. In the PCH a large group can be on the order of 50,000 animals. Pipelines and development infrastructure could change the PCH's migratory routes.

Land Use and Protection in the PCH's Canadian Range

- In Canada, areas where the PCH has occasionally calved have been given permanent protection in the Northern Yukon National Park, established in 1984. Before the sensitivity of this area was known, 15 - 20 years ago, three exploratory wells were drilled in the periphery of this area. This by no means indicates that this area might not contain significant oil and gas resources. A further 69 exploratory wells were drilled between 1957 and 1985 in the remainder of the PCH Canadian range, not in the Canadian calving grounds, as some have claimed.

- In spite of significant pressure for further mineral exploration and other development, e.g. of a port at Stokes Point, the Canadian Government, through the Western Arctic (Inuvialuit) Claims Settlement Act, established wilderness protection for the most sensitive areas of the PCH range with the creation of the Northern Yukon National Park, and a special conservation regime for the remaining areas of the Yukon North Slope.

- The Dempster Highway was completed in 1979 across a portion of the PCH southern wintering range. The highway does not cross the herd's Canadian calving grounds. This road is comparatively easy for the PCH to cross because it is a single, low-use route in mountainous terrain, unlike the road-pipeline complexes on the flat coastal plain. Furthermore, no hunting is allowed for one kilometer on either side of the highway at any time.

The People

- There are seven thousand members of the Gwitch'in Nation in the Yukon Territory and in Alaska who have depended on the PCH for vital subsistence and cultural needs for centuries. If this herd becomes unavailable to them, either because of dwindling numbers or through a change in its migratory route, the Gwitch'in do not have other options, unlike some coastal communities on the North Slope. The herd is also important to other Indians and Inuit in the Canadian north.

Northern Development

- Canada is not opposed to environmentally sensitive development in the North or in any other frontier areas. However, Canada is especially conscious of the need to protect lands that have particular environmental sensitivity, such as the calving grounds of the Porcupine Caribou Herd, and to guard against potential transboundary impacts of development.

THE ASSOCIATED GENERAL CONTRACTORS OF AMERICA
1957 E Street, N.W. • Washington, D.C. 20006 • (202) 393-2040 • FAX (202) 347-4004
MARVIN M. BLACK, *President* ROBINS H. JACKSON, *Senior Vice President* BYRON L. FARRELL, *Vice President*
LAWRENCE J. McGOUGH, *Treasurer* HUBERT BEATTY, *Executive Vice President*

May 7, 1991

The Honorable J. Bennett Johnston
Chairman
Energy & Natural Resources Committee
United States Senate
364 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Mr. Chairman:

At its 68th Annual Convention, March 1987, the Associated General Contractors of America urged "that Congress open the coastal plain of the Arctic National Wildlife Refuge (ANWR) to environmentally and responsible oil and gas leasing, exploration, development and production." Our position on this issue, so critical to our country's energy independence, remains unchanged.

I understand that the Energy and Natural Resources Committee may address the ANWR provisions in mark-up of S.341, the Comprehensive Energy Policy bill, the week of May 13.

The need for orderly domestic oil and gas development has been clearly demonstrated, as has the fact that such development can be done in a way to protect the environment and wildlife.

Our industry experience on the North Slope demonstrates that the nation's energy needs can coexist with the wildlife and environment found in the Arctic region. Construction techniques employed include: directional drilling, smaller and consolidated facilities, winter construction, use of temporary ice roads, special arctic equipment and elevated pipelines.

The AGC urges your support in committee markup for the ANWR provisions providing for oil and gas exploration and development in an environmentally responsible manner.

Sincerely,

Marvin M Black

Marvin M. Black
President

CITY OF VALDEZ, ALASKA
GATEWAY TO THE INTERIOR

ENERGY AND NATURAL RESOURCES
MAY 1
WASHINGTON, D.C.

May 8, 1991

Senator J. Bennett Johnston
U.S. Senate
Washington, DC 20510

Dear Senator Johnston:

Enclosed is a resolution passed by the Valdez City Council on May 6, 1991, supporting the opening of the Arctic National Wildlife Refuge (ANWR) for oil exploration. The leaders of this community feel strongly that the energy independence of the nation requires that several steps be taken in formulating a national energy policy. Conservation and development of alternative energy sources are important legs of this policy, but increased domestic oil and gas production is the other vital leg of a comprehensive program. A small portion of Arctic Coastal Plain located within ANWR is rated as the most likely prospect for a major domestic oil and gas find. Relative to Alaska's immense size, the area to be explored is very small and work can be done with minimal environmental disruption.

The system of transporting oil through the Trans-Alaska Pipeline System has been greatly strengthened since the Exxon Valdez disaster. This point is rarely raised, but it is possible for all of us to learn from this horrible mistake. Oil laden tankers are now escorted by support craft which are equipped with oil boom and skimmers. The largest oil skimmer in the United States, capable of collecting 84,000 gallons of oil per hour, will be stationed here in Valdez. The oil industry has made great strides in improving its readiness for future oil spills in terms of upgrading and positioning equipment, improving its emergency management capabilities, and in working with communities and other interested groups.

The Alaska Regional Citizens Advisory Council has been funded by the oil industry and has been designated by President Bush to also act on behalf of the Federal government as an advisory and oversight panel for the shipment of oil out of the Valdez terminal. This group is fully functional and has already made significant recommendations to improve the oil spill contingency planning of the oil industry.

P.O. BOX 307 • VALDEZ, ALASKA 99686
TELEPHONE (907) 835-4313 • TELEX 25-381 • TELECOPIER (907) 835-2992

Senator Bennett Johnston
May 8, 1991
Page 2

The world is different for all of us as a result of the Exxon Valdez accident. Systems are better and environmental awareness is greater. The nation needs the energy and the City of Valdez believes we have the ability to transport the energy safely.

Thank you for your consideration of the vital topic of opening ANWR to oil and gas exploration.

Sincerely,

Doug Griffin

Doug Griffin
City Manager

DG:blp

CITY OF VALDEZ, ALASKA

RESOLUTION NO. 9142

A RESOLUTION OF THE CITY COUNCIL OF THE CITY OF VALDEZ, ALASKA, SUPPORTING THE OPENING OF THE COASTAL PLAIN OF THE ARCTIC NATIONAL WILDLIFE REFUGE (ANWR) TO OIL AND GAS DEVELOPMENT.

WHEREAS, Alaska's Arctic National Wildlife Refuge includes more than 19 million acres of land, amounting to approximately 5% of the entire state land mass; and

WHEREAS, the Coastal Plain is approximately 8% of the refuge, and it is considered to be highly prospective to the discovery of large quantities of oil and gas; and

WHEREAS, the U.S. Senate Committee on Energy and Natural Resources is presently reviewing the issue of allowing this area to be open for oil and gas exploration; and

WHEREAS, it is in the best interest of national security, the State of Alaska and the City of Valdez for the continued environmentally sound development of oil and gas in the State of Alaska; and

WHEREAS, opening of ANWR Coastal Plain to further exploration, development and production will generate increased employment and business opportunities for all Alaskans and all Americans; and

WHEREAS, since the Exxon Valdez oil spill, industry has taken substantial steps towards preventing similar events from reoccurring by way of the creation of citizens oversight of the oil industry consisting of the Regional Citizen's Advisory Council; and

WHEREAS, the Regional Citizen's Advisory Council provides recommendations to the oil industry regarding the operation of the oil terminal in Valdez and the crude oil tankers calling on that terminal; and

WHEREAS, the Regional Citizen's Advisory Council and committees presently consists of approximately forty-four (44) citizens from the areas that were affected by the 1989 Exxon Valdez oil spill; and

WHEREAS, the Oil Pollution Act of 1990 provides additional safe guards to further prevent another oil spill.

CITY OF VALDEZ, ALASKA RESOLUTION NO. 9142

THEREFORE, BE IT RESOLVED that the City Council of the City of Valdez, Alaska, strongly urges the Senate Committee on Energy and Natural Resources and the Congress of the United States to open the ANWR Coastal Plain to environmentally responsible oil and gas exploration, development and production.

PASSED AND APPROVED BY THE CITY COUNCIL OF THE CITY OF VALDEZ, ALASKA, THIS 6th day of May, 1991.

CITY OF VALDEZ, ALASKA

By: Lyn Chrystal
Lynn Chrystal, Mayor

ATTEST:

Jeanne Donald
Jeanne Donald, City Clerk

Affiliated with the AFL-CIO

National
Marine Engineers'
Beneficial
Association

444 North Capitol Street • Suite 800 • Washington, D.C. 20001 • 202-347-8585

May 13, 1991

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
[illegible] 1991
WASHINGTON, D.C. 20510

The Honorable J. Bennett Johnston
United States Senate
136 Hart Office Building
Washington, DC 20510-1802

Dear Senator Johnston:

On behalf of the more than 50,000 members of the National Marine Engineers' Beneficial Association, representing American licensed and unlicensed merchant mariners aboard U.S-flag vessels, I urge you to support oil and gas leasing in the Arctic National Wildlife Refuge when Title IX of S. 341 is marked up by the Committee.

Opening a portion of the ANWR area to energy development is critical to America's future energy security. It is also crucial to any national energy plan, because it represents a key element in any overall compromise that balances conservation and development. Furthermore, the funds that result from ANWR will help achieve energy security goals that otherwise would be impossible to realize in today's budget climate.

Both our members and our industry are extremely pleased that essential restrictions against the export of ANWR oil have been included in S. 341. Any attempt to remove or water down these restrictions would undermine totally the two key justifications for ANWR development -- the use of ANWR oil to benefit American consumers and the importance of ANWR oil to our nation's energy security. Not only are these restrictions extremely important to our industry, which carries Alaska North Slope crude to the rest of the United States, but they strengthen Title IX by making it clear that ANWR oil development will serve the interest of all Americans and not merely increase profits for a few or provide energy security for the industries of our strongest economic competitors.

C. E. DeFRIES
President

C. E. DODSON
Secretary Treasurer

THOMAS C. HARPER
Executive Vice President

R. F. SCHAMANN
Vice President

SHANNON J. WALL
Vice President

R. T. McKAY
Vice President

The Honorable J. Bennett Johnston
Page Two
May 13, 1991

ANWR oil exploration and development will mean continued maritime jobs and a strong U.S.-flag tanker fleet; as part of S. 341, it represents a constructive compromise between conservation and development; and it is vital to American energy security. I urge that you support Title IX of S. 341 as drafted.

Sincerely,

C. E. DeFries

C. E. DeFries
President

CED/cmv

RECEIVED MAY 1 4 1991

AMERICAN MARITIME CONGRESS
Hall of the States Building, 444 North Capitol Street, Suite 801, Washington, DC 20001-1512

J.P. WALTERS
Executive Director

May 14, 1991

The Honorable J. Bennett Johnston
United States Senate
Committee on Energy & Natural
  Resources
364 Dirksen Building
Washington, D.C. 20510

Dear Mr. Chairman:

On behalf of the American Maritime Congress, representing more than one hundred U.S.-flag ship-operating companies, I urge that you support in markup oil exploration and development in the Arctic National Wildlife Refuge as proposed in Title IX of S. 341.

Not only is ANWR oil exploration and development important to our nation's energy security and to a balanced program of conservation and development, but continued flow of Alaska North Slope oil is vital to the U.S.-flag maritime industry. Currently the carriage of Alaska oil to the "Lower 48" employs approximately half the U.S.-flag tanker fleet. These oil cargoes provide thousands of jobs in ship operations and ship repairs, employ more than sixty vessels, and help maintain a fleet of militarily-useful U.S.-flag tankers.

Title IX of S. 341 provides for ANWR development in an environmentally-sound manner. By clearly preventing exports, it explicitly assures that any oil found will benefit American consumers and reduce reliance on imported oil. And, it will improve our nation's energy security for decades to come. Every barrel we produce at home is one less barrel that must be imported from abroad, one less barrel that has to come from politically unstable, insecure regions of the world.

It is time to move on ANWR development now. We urge you to support ANWR development, with its no-export provision, when Title IX is marked-up by the Committee. Thank you for your consideration of this matter.

Sincerely,

J. P. Walt

J. P. Walters
Executive Director

Telephone (202) U.S. SHIPS (202-877-4477)   Cable USFLAG   Fax (202) 638-2833

COALITION FOR AMERICAN ENERGY SECURITY

M. Isabelle Tapia
Executive Director

STATEMENT OF
ISABELLE TAPIA
EXECUTIVE DIRECTOR
FOR THE
COALITION FOR AMERICAN ENERGY SECURITY
ON THE COASTAL PLAIN STUDY AREA OF THE
ARCTIC NATIONAL WILDLIFE REFUGE
BEFORE THE
SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

March 12, 1991

Mr. Chairman, Members of the Committee, I appreciate the opportunity to testify at today's hearing on the Coastal Plain area of the Arctic National Wildlife Refuge (ANWR).

I am Isabelle Tapia, the Executive Director of the Coalition for American Energy Security (Coalition). The Coalition is a broad-based national assembly that includes more than 56 organizations representing businesses, labor unions, agriculture, transportation, recreation, trade associations and Native Americans who are deeply concerned about our nation's declining domestic crude oil production and our growing dependence on insecure sources of foreign crude oil. The Coalition was formed in 1987 for the sole purpose of informing the American public on

1050 Thomas Jefferson Street, N.W. — Sixth Floor, Washington, D.C. 20007 (202) 333-7484

MEMBERSHIP: Air Transport Association • Alaska Oil & Gas Association • American Association of Blacks in Energy • American Association of Petroleum Landmen • American Institute of Merchant Shipping • American Maritime Congress • American Mining Congress • American Petroleum Institute • American Sheep Industries Association • American Trucking Associations • Americans for a Rational Energy Policy • Arctic Slope Regional Corporation • The Associated Builders and Contractors • The Associated General Contractors of America • Association of Oil Pipelines • BP America • Brown & Root, Inc. • Caterpillar Inc. • Chevron U.S.A. Inc. • Columbia Helicopter Inc. • Cooper Industries, Inc. • Crowley Maritime • Dresser Industries, Inc. • Fluor Corp. • HEHR International Inc. • Highway Users Federation • Independent Petroleum Association of America • International Association of Drilling Contractors • International Association of Geophysical Contractors • Interstate Natural Gas Association of America • Marriott Corporation • NAACP - Anchorage Branch • National Association of Home Builders • National Association of Manufacturers • National Association of Realtors • National Cattlemen's Association • National Coal Association • National Council of Farmer Cooperatives • The National Grange • National Inholders Association • National Marine Engineers Beneficial Association • National Marine Manufacturers Association • Natural Gas Supply Association • NL Industries, Inc. • National Ocean Industries Association • National Tour Association, Inc. • Petroleum Equipment Suppliers Association • Public Lands Council • Recreational Vehicle Industry Association • Rocky Mountain Oil and Gas Association • The Transportation Institute • U.S. Chamber of Commerce • U.S. Hispanic Chamber of Commerce • Western States Petroleum Association

the critical policy significance of the future status of the Coastal Plain area of ANWR to the Nation's national security and economic independence. A list of the Coalition's current membership is appended to my testimony and is submitted for the record in this proceeding.

Nearly four years ago there was tension over the American reflagging of oil tankers in the Persian Gulf. In August of 1990 the United States began the process of sending more than 530,000 of our sons and daughters to the Persian Gulf. This mission was to protect not only America's oil but the world's oil supply. Members of Congress must ask themselves whether there are better ways to meet U.S. energy needs and sustain economic growth than risking the lives of our youth.

One answer -- proposed in Title IX of S.341, the National Energy Security Act of 1991, sponsored by this Committee's Chairman and Ranking Minority Member -- is to make available for leasing, exploration and development, the Coastal Plain study area of ANWR, east of Prudhoe Bay. Access to this area is also proposed in President Bush's budget, in bills introduced by the Alaska delegation, and in President Bush's National Energy Strategy and legislation to implement the strategy (S. 570).

Since 1987, the Coalition for American Energy Security -- through its representation of businesses, labor unions, agriculture, transportation, recreation, Native Americans and others -- has been deeply concerned about the nation's declining domestic crude oil production and its growing dependence on insecure sources of foreign oil.

We believed then, and continue to believe today, after the war in the Persian Gulf, that environmentally sound development of ANWR's Coastal Plain area represents the nation's best opportunity to relieve the economic and national security pressures excessive imports bring. Since 1987, our convictions and the facts that support them have only grown stronger, they have become more self-evident.

Since the late 1970s, Alaska's North Slope has provided as much as 25 percent of the nation's total domestic crude oil production. But that output began to decline in 1989. During 1990, production declined by 100,000 barrels a day. It is projected that by the year 2000 production will be down to 600,000 B/D; by the year 2014 these reserves will be nearly tapped out.

Meanwhile, imports of foreign oil are running higher than before the Arab oil embargo of 1974. Since the first half of 1985 imports have risen nearly 80 percent, while production has dropped by nearly 20 percent. Last year, oil production in the United States hit its lowest point in 29 years and foreign imports accounted for 46.9 percent. In some months, imports supplied more than 50 percent of the country's need. Oil experts attribute the growing gap more to U.S. production decline, than to large increases in domestic demand. Imports must balance demand with supply.

Increasing U.S. oil production could and would have significant results. Every barrel of Alaskan oil reduces the need to import a barrel from overseas, thus reducing our balance of payments deficit. In fact, Alaskan oil reduced our balance of payments since 1985 alone by over 17.5 billion dollars.

Leasing the Coastal Plain would have other benefits as well. These include:

- jobs and orders for products from all 50 states, with major economic development in all regions of the country (see Appendix A);
- Significant tax and royalty revenue for the federal budget -- potentially up to $128 billion over 125 years of development if prices reach $40 a barrel;
- Continued economic activity on Alaska's North Slope for the Inupiat Eskimos who own a small percentage of the Coastal Plain region and who depend on oil exploration and production for jobs and tax revenue to fund schools, hospitals, sanitation services, etc.

Though their subsistence needs dictate that they be strong proponents of environmental safeguards, Inupiat Eskimos are leading the fight to remove restrictions on Coastal Plain oil development.

ANWR development frequently comes under attack from those who question the impact it could have on the Arctic environment. But numerous studies and development of other fields on the North

Slope have proven that environmentally sound development not only is possible, it is a reality.

Miles of elevated pipelines, caribou crossing ramps, directional drilling, roads built from ice and seasonal operation of equipment are but a few examples of the efforts developed to successfully meet this challenge.

The results are noticeable and clear. Waterfowl and other migratory birds thrive in areas near production facilities. The Central Arctic caribou herd on the North Slope has tripled in number to 18,000 animals since oil operations began.

Critics of development of the Coastal Plain belittle the amount of oil believed to lie under the barren tundra. But when Congress set aside 19 million acres as a Refuge -- half of it as wilderness -- it identified the Coastal Plain study area as having very high oil and gas potential and ordered an evaluation of that potential, along with its fish and wildlife resources. That study released in April 1987, concluded that the Coastal Plain is the most outstanding oil and gas frontier remaining in the United States. The Department of the Interior recommended that the entire 1.5 million acre area be available for oil and gas leasing, under stringent environmental regulations.

Moreover, on March 12, 1987, the National Wildlife Federation released a report that included a consulting independent geologist's report which concluded that all prior projections of the Coastal Plain's crude oil reserves are "conservative in regard to the oil and gas exploration possibilities."

The Interior Department has estimated that as many as 9.2 billion barrels of oil may be commercially produced from the Coastal Plain. After reviewing geological data from four wells drilled near the Coastal Plain, reprocessed geophysical data collected from the area and additional seismic data from offshore areas near the Coastal Plain, the Department, just last month, more than doubled previous probability estimates for a commercial oil discovery in the Coastal Plain from 19 percent to 46 percent. This is a 1 in 2, rather than a 1 in 5, chance in discovering commercial quantities of oil in the Coastal Plain study area.

Oil production at the mean estimate of 3.2 billion barrels or 600,000 B/D, would replace nearly 10 percent of the oil the United States imported last year. If the strike is closer to the high estimate of 9 billion barrels, ANWR oil could reduce our oil imports by nearly 25 percent. Or, to look at it from another perspective, production in the Coastal Plain would roughly equal the amount of oil the United States imported from Iraq the first five months of 1990.

The future of the 1.5 million acre Coastal Plain study area is addressed in Title IX of the National Energy Security Act of 1991 (S.341). Title IX recommends access to the Coastal Plain study area of the Arctic National Wildlife Refuge for oil and gas leasing. The Coalition for American Energy Security supports the orderly development, with prudent environmental regulation, of the Coastal Plain's potentially huge oil and gas resources.

The future of the Coastal Plain study area of ANWR is one of the most significant energy policy and national security issues to come before the Congress in recent decades.

The Coastal Plain presents the Congress and the American people with a once-in-a-lifetime opportunity and a straightforward question: Should the 1.5 million acre Coastal Plain:

A) be designated as wilderness (used by fewer than 175 people a year) and permanently closed to oil and gas exploration and development? or

B) be opened to oil and gas leasing, exploration and development under prudent environmental regulations similar to those which govern the successful relationship between oil development and prospering fish and wildlife resources at the nearby Prudhoe Bay oil fields?

Given the huge potential of the small 1.5 million acre Coastal Plain study area for major new discoveries of critically needed domestic crude oil, we believe it would be reckless and irresponsible to designate this area as wilderness. It is conceivable that if the 1.5 million acre Coastal Plain is made available to responsible, properly regulated leasing, exploration and development, it will enable Alaska's North Slope to continue to provide a major domestic alternative to imported oil and rising balance of payments.

While this is a national issue, the future of the Coastal Plain study area may also affect other states directly. Attached to this statement (as Appendix A) is a map which shows that a conservative $10.5 billion was spent on Alaska North Slope development throughout the United States between 1980 and 1986.

The Coastal Plain study area of ANWR presents the Congress and the nation with an opportunity to take early, well-planned, strategic steps to avoid undue reliance on insecure foreign sources for imported oil; an opportunity to "act" rather than "react" to the needs of the American people.

The membership of the Coalition for American Energy Security believes that making the Coastal Plain of ANWR available for oil and gas leasing is responsible energy policy and a matter of vital concern to American consumers and to the most vital interests of the United States.

It is also a responsible and sensible way for the Congress to address the economic and security questions which led to U.S. involvement in the war against Iraq's aggression against the neighbors in the oil-rich Gulf.

On behalf of our Coalition's 56 members who support opening the Coastal Plain of ANWR, I urge the Members of the Senate Energy and Natural Resources Committee to support legislation to open the Coastal Plain to responsible development. We oppose designating the area as wilderness.

COALITION FOR AMERICAN ENERGY SECURITY

M. Isabelle Tapia
Executive Director

COALITION FOR AMERICAN ENERGY SECURITY MEMBERSHIP LIST

AIR TRANSPORT ASSOCIATION

ALASKA OIL AND GAS ASSOCIATION

AMERICAN ASSOCIATION OF BLACKS IN ENERGY

AMERICAN ASSOCIATION OF PETROLEUM LANDMEN

AMERICAN PETROLEUM INSTITUTE

AMERICANS FOR A RATIONAL ENERGY POLICY

AMERICAN INSTITUTE OF MERCHANT SHIPPING

AMERICAN MINING CONGRESS

AMERICAN SHEEP INDUSTRIES ASSOCIATION

AMERICAN TRUCKING ASSOCIATIONS

ARCTIC SLOPE REGIONAL CORPORATION

THE ASSOCIATED BUILDERS AND CONTRACTORS

THE ASSOCIATED GENERAL CONTRACTORS OF AMERICA

ASSOCIATION OF OIL PIPELINES

BP AMERICA

BROWN & ROOT, INC.

CATERPILLAR INC.

CHEVRON U.S.A INC.

COLUMBIA HELICOPTER, INC.

1050 Thomas Jefferson Street, N.W. — Sixth Floor, Washington, D.C. 20007 (202) 333-7484

MEMBERSHIP: Air Transport Association • Alaska Oil & Gas Association • American Association of Blacks in Energy • American Association of Petroleum Landmen • American Institute of Merchant Shipping • American Maritime Congress • American Mining Congress • American Petroleum Institute • American Sheep Industries Association • American Trucking Associations • Americans for a Rational Energy Policy • Arctic Slope Regional Corporation • The Associated Builders and Contractors • The Associated General Contractors of America • Association of Oil Pipelines • BP America • Brown & Root, Inc. • Caterpillar Inc. • Chevron U.S.A. Inc. • Columbia Helicopter Inc. • Cooper Industries, Inc. • Crowley Maritime • Dresser Industries, Inc. • Fluor Corp. • HEHR International Inc. • Highway Users Federation • Independent Petroleum Association of America • International Association of Drilling Contractors • International Association of Geophysical Contractors • Interstate Natural Gas Association of America • Marriott Corporation • NAACP - Anchorage Branch • National Association of Home Builders • National Association of Manufacturers • National Association of Realtors • National Cattlemen's Association • National Coal Association • National Council of Farmer Cooperatives • The National Grange • National Inholders Association • National Marine Engineers Beneficial Association • National Marine Manufacturers Association • Natural Gas Supply Association • NL Industries, Inc. • National Ocean Industries Association • National Tour Association, Inc. • Petroleum Equipment Suppliers Association • Public Lands Council • Recreation Vehicle Industry Association • Rocky Mountain Oil and Gas Association • The Transportation Institute • U.S. Chamber of Commerce • U.S. Hispanic Chamber of Commerce • Western States Petroleum Association

COOPER INDUSTRIES, INC.

CROWLEY MARITIME

DRESSER, INDUSTRIES, INC.

FLUOR CORPORATION

HEHR INTERNATIONAL INC.

HIGHWAY USERS FEDERATION

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

INTERNATIONAL ASSOCIATION OF DRILLING CONTRACTORS

INTERNATIONAL ASSOCIATION OF GEOPHYSICAL CONTRACTORS

INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

JOINT MARITIME CONGRESS

MARRIOTT CORPORATION

NAACP-ANCHORAGE BRANCH

NATIONAL ASSOCIATION OF HOME BUILDERS

NATIONAL ASSOCIATION OF MANUFACTURERS

NATIONAL ASSOCIATION OF REALTORS

NATIONAL CATTLEMEN'S ASSOCIATION

NATIONAL COUNCIL OF FARMER COOPERATIVES

NATIONAL INHOLDERS ASSOCIATION

NATIONAL MARINE ENGINEERS BENEFICIAL ASSOCIATION

NATIONAL OCEAN INDUSTRIES ASSOCIATION

NATIONAL TOUR ASSOCIATION, INC.

NATURAL GAS SUPPLY ASSOCIATION

NL INDUSTRIES, INC.

PETROLEUM EQUIPMENT SUPPLIERS ASSOCIATION

PUBLIC LANDS COUNCIL

RECREATION VEHICLE INDUSTRY ASSOCIATION

ROCKY MOUNTAIN OIL AND GAS ASSOCIATION

THE NATIONAL GRANGE

THE TRANSPORATION INSTITUTE

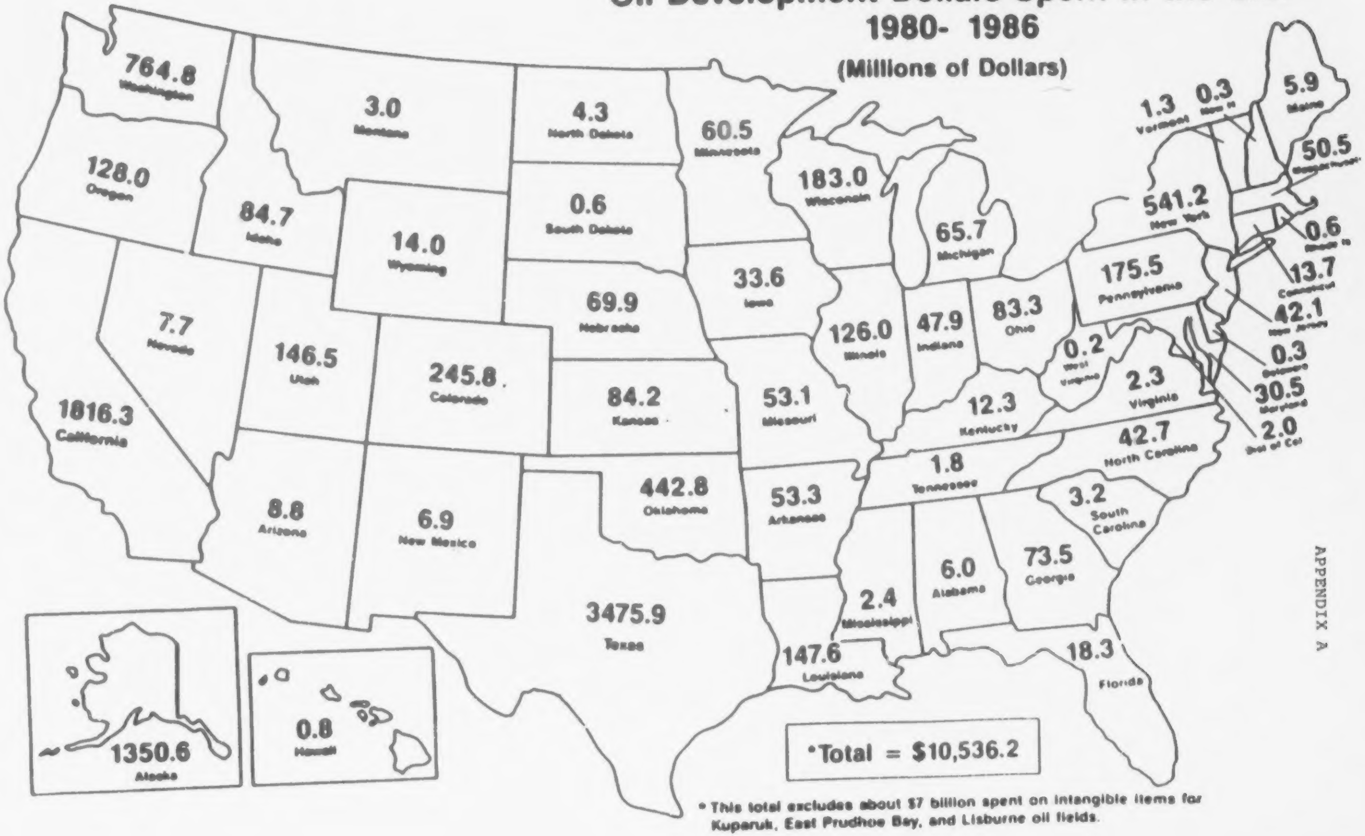
U.S. CHAMBER OF COMMERCE

U.S. HISPANIC CHAMBER OF COMMERCE

WESTERN STATES PETROLEUM

APPENDIX A

North Slope Alaska
Oil Development Dollars Spent in the U.S.
1980- 1986
(Millions of Dollars)


764.8
Washington
128.0
Oregon
1816.3
California
84.7
Idaho
7.7
Nevada
3.0
Montana
14.0
Wyoming
146.5
Utah
8.8
Arizona
245.8
Colorado
6.9
New Mexico
4.3
North Dakota
0.6
South Dakota
69.9
Nebraska
84.2
Kansas
442.8
Oklahoma
3475.9
Texas
60.5
Minnesota
33.6
Iowa
53.1
Missouri
53.3
Arkansas
147.6
Louisiana
183.0
Wisconsin
126.0
Illinois
65.7
Michigan
47.9
Indiana
83.3
Ohio
12.3
Kentucky
1.8
Tennessee
2.4
Mississippi
6.0
Alabama
73.5
Georgia
18.3
Florida
3.2
South Carolina
42.7
North Carolina
2.3
Virginia
0.2
West Virginia
175.5
Pennsylvania
541.2
New York
1.3
Vermont
0.3
New H
5.9
Maine
50.5
Massachusetts
0.6
Rhode Is
13.7
Connecticut
42.1
New Jersey
0.3
Delaware
30.5
Maryland
2.0
Dist of Col
1350.6
Alaska
0.8
Hawaii

*Total = $10,536.2

* This total excludes about $7 billion spent on intangible items for Kuparuk, East Prudhoe Bay, and Lisburne oil fields.

Statement Of
Crowley Maritime Corporation

In Support Of

Title IX Of The National Energy Security Act Of 1991 (S.341)
Opening The Arctic National Wildlife Refuge
To Oil And Gas Leasing Exploration And
Production

Submitted To The Senate Committee On
Energy And Natural Resources

March 12, 1991

The Position Of Crowley Maritime Corporation Concerning The Opening Of The Coastal Plain Of The Arctic National Wildlife Refuge (ANWR) To Oil And Gas Exploration, Development, And Production.

Crowley Maritime Corporation strongly favors opening the coastal plain of ANWR to oil development. We believe it is in the best interests of the nation to do so, and it is potentially beneficial to our company and its employees.

The United States has good reason to be concerned about future shortages in the supply of oil. The percentage of oil we import has risen substantially in the past two years and now represents about 50% of the nation's requirements. That much reliance on other countries for a major energy resource endangers industries that produce our goods, our transportation systems, and the heating of our homes. The costs of goods which have oil as an ingredient could rise, returning us to the days, not too distant in the past, of double-digit inflation.

It takes 10 to 15 years to develop petroleum sources in the Arctic. Our existing domestic production of oil is declining, so we need to start now to explore areas where there is a good possibility of finding new sources of oil.

The U.S. Department of the Interior estimates that there are substantial quantities of oil that can be produced from the ANWR coastal plain. Their estimate can only be verified, however, through drilling.

Revenues from the generation of oil in the ANWR coastal plain will benefit the federal and Alaska state governments and the economy of the nation. Crowley Maritime provided almost all of the ocean transportation of materials and supplies for the Prudhoe Bay oil fields over the past eighteen years. We could reasonably expect to provide the same kind of service if and when the ANWR coastal plain is developed. Improvement in the Alaskan economy will result in more goods being shipped to Alaska for commercial and industrial development and consumption.

Well-intentioned opponents of oil development on the ANWR coastal plain are concerned about effects on the environment. They argue that oil development will cause the demise of caribou and other wildlife. Experience at Prudhoe Bay, the site of the largest discovery to date in the United States, indicates otherwise. There the number of caribou has risen substantially since petroleum operations began, and they graze and move about the area undisturbed by the pipeline and other facilities. The oil companies and the service companies, like Crowley, that support them, understand the need to preserve the environment and have shown their willingness to do so.

If the coastal plain of the ANWR is not developed for oil production under the carefully controlled time schedule envisioned, almost assuredly the day will come when development will be required on an emergency basis. Then the priority for getting the oil out at any cost may well override the concern for the welfare of the wildlife and the environment.

Crowley Maritime believes that development of the ANWR coastal plain for oil production is crucial and that preservation of the environment can be assured. The work should commence now to assure that it is done methodically and with care.

Highway
Users Federation
FOR SAFETY AND MOBILITY

Statement of

the

HIGHWAY USERS FEDERATION

for submission to the

Committee on Energy and Natural Resources

United States Senate

on S. 341

"National Energy Security Act of 1991"

Hearing Date: March 12, 1991

1776 Massachusetts Avenue, N.W., Washington, D.C. 20036 (202) 857-1200

The Highway Users Federation for Safety and Mobility is a coalition of businesses, industries and associations in support of America's highway transportation system. Our membership consists of more than 400 companies and associations representing the major suppliers of highway transportation services and products as well as the major users of the nation's highways. The Federation is affiliated with highway user groups in every state.

We are pleased by the provisions of S.341 which would allow for the exploration and development of energy deposits in the Arctic National Wildlife Reserve (ANWR). The Administration also has recognized, in the recently released National Energy Strategy, the importance of continued development of new domestic resources such as those which may be found in the ANWR region.

American transportation depends almost exclusively on petroleum-based liquid fuels and will continue to do so in the foreseeable future. In our judgment, ensuring the availability of fuels for transportation is a matter of highest national priority.

We support free-market oriented energy policies that will stimulate prompt and cost-efficient location and development of domestic energy resources. We are convinced that the nation's industrial and economic health will benefit from reduced dependence on imported fuels. For these reasons, the Highway Users Federation has consistently supported environmentally sound energy exploration and development in the Arctic.

Each year our society becomes more dependent on motor vehicles for basic transportation. In 1989, Americans travelled more than 2.1 trillion vehicle miles. If the current rate of growth continues, by the Year 2000 we will be driving our motor vehicles some three trillion miles per year!

This increase reflects demographic and economic shifts which the nation is experiencing: population movement to the so-called Sun Belt; shifting of industrial development sites; growth in service industries; suburbanization; and so forth.

If we want employment to keep pace with our growing population, if we want to enjoy continuing growth in our economy and standard of living, then transportation - particularly highway transportation - also must grow to meet critical emerging needs. The continued availability of suitable fuel sources at reasonable cost is a basic necessity for the smooth functioning of a healthy, growing economy.

The American public has enjoyed adequate and reasonably priced fuel supplies, but only at the cost of increased dependence on foreign sources. We must not forget the harsh lessons learned from the oil embargoes of the 1970's, and even in just the past several months, when threats to international oil supplies resulted in uncertain supplies and rapid price increases. Though the situation in the Middle East has improved, there can be little doubt that increased domestic supplies would help insulate the national economy from any sudden and unexpected reduction in the availability of imported oil.

We feel strongly that this issue must be raised now because the transportation sector is dependent on petroleum based fuels. Transportation use accounts for almost two-thirds of the nation's consumption of oil, according to the Department of Energy. This rate of consumption is unlikely to drop in the near future, despite significant increases achieved to date in vehicle fuel economy through technical advances and weight reduction.

The Federation appreciates the Corporate Average Fuel Economy (CAFE) language of S.341 and feels the proposal to allow administrative determination of a CAFE standard, recognizing the technological feasibility and economic practicality as a part of the decision-making process, is greatly preferable to other pending measures which would utilize the federal command and control process.

Auto manufacturers are working to produce variable fuel vehicles. The use of gasoline\alcohol\ether blends (reformulated) fuels are being studied, primarily on environmental grounds through the implementation of the Clean Air Act, but also as a petroleum replacement. Though these early steps towards reduced petroleum dependence are underway, the extent of the existing fuel distribution system and the abundance of petroleum powered vehicles makes any sudden shift to another fuel source unlikely in the near term.

Such change will, by necessity, be a gradual process. It has taken more than a year to formulate the National Energy Strategy and would take more time to approve and implement the policies it proposes. There would be an even greater delay before results might be observed in the form of changed patterns of fuel usage in the United States.

The nation's economy depends on the movement of goods and people from point to point. This movement is accomplished predominantly through the use of petroleum based fuels. Until a replacement or alternate fuel is available with a distribution network on an adequate scale, we believe that the location and development of domestic oil resources is a mandatory task, not an option.

This is why the U.S. highway user community continues to feel that the early opening the Coastal Plain of ANWR to energy exploration is in the national interest. The provisions of Title IX of S. 341 would serve this national interest and we recommend the adoption of provision to all members of Congress.

INTERNATIONAL ASSOCIATION OF DRILLING CONTRACTORS

Chairman
Alain Roger
Sedco Forex

Vice Chairman
Burt Harkins
Harkins & Co.

Secretary-Treasurer
Randy James
Chesley Pruet Drilling

International Headquarters, Houston, Texas:

President
A. Lee Hunt, Jr.

Mailing Address:
P.O. Box 4287
Houston, Texas
77210-4287

Phone: 713/578-7171
Fax: 713/578-0589
Telex: 516985

Street Address:
15810 Park 10 Place
Suite 242
Houston, Texas
77084-5134

Washington Office:

Senior Vice President – Government Affairs
Brian T. Petty

1901 L Street, NW
Suite 702
Washington, DC
20036-3506

Phone: 202/293-0670
Fax: 202/872-0047

European Office:

Vijverlaan 17, Velp
P.O. Box 13
6880 AA Velp
The Netherlands

COMMENTS

of the

INTERNATIONAL ASSOCIATION OF DRILLING CONTRACTORS

on

Oil and Gas Leasing

in the

Arctic National Wildlife Refuge

filed with the

SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

Washington, D.C.

Hearing Record of
March 12, 1991

This statement is submitted on behalf of the International Association of Drilling Contractors (IADC), a trade association representing virtually the entire worldwide contract drilling industry, most of which is headquartered in the United States.

IADC strongly supports Title IX of S. 341 (National Energy Security Act of 1991) that recommends to Congress that the Arctic National Wildlife Refuge (ANWR) coastal plain be opened to oil and gas leasing. Access to this area is also proposed by the Department of the Interior in President Bush's budget, in bills introduced by the Alaskan Congressional delegation, in President Bush's National Energy Strategy, and in legislation to implement that strategy (S. 570).

At a time of continuing political turmoil and terrorism in the Middle East, it is essential that the United States assign the highest priority to finding and developing additional oil and gas resources within its own borders. The U.S. Department of the Interior (DOI) estimates that there are billions of barrels of oil to be found under the ANWR coastal plain, with a 46% probability of a commercial oil discovery in the coastal plain.

Although there is uncertainty inherent in all oil and gas resource assessment methods which do not include actual drilling, DOI estimates for the ANWR coastal plain a very large crude oil potential on the same order of magnitude as the nearby Prudhoe Bay field, the largest U.S. discovery to date.

Crude oil from the North Slope's producing oil fields are already contributing nearly 25 percent to U.S. oil production. This nation's dependency on foreign oil could increase markedly in the years ahead, as these fields--along with older fields in the lower 48 States--reach peak production and start to decline, as many already have. The U.S. must turn to Alaska's undiscovered oil and gas if our future energy supply is to be augmented.

If we therefore accept the fact that these resources will eventually be needed, the ANWR coastal plain development is particularly urgent at this time as an element to help stabilize economic conditions in the severely depressed U.S. onshore producing industry and the contract drilling business that depends on it. It is difficult to exaggerate the extent of the current depression in the petroleum services industry. Hundreds of thousands of workers have lost their jobs. Hundreds of contract drilling, equipment, and supply companies have either merged or gone bankrupt as the oil companies have been forced to drastically reduce their spending on exploration and production projects.

According to Baker-Hughes International in Houston, Texas, the 1981 U.S. average number of rotary drilling rigs running was 3,969. The 1986 number was 964. The current rig count is almost exactly the same as it was then: flat. The number of drilling rigs available for work in 1982 was approximately 5,500. Today there remain but 2,500 or so; the others have been lost through physical deterioration or "cannibalization" for parts.

The growing gap between domestic consumption and production has been filled by an increase in oil imports. Recent import estimates run to nearly 50% of U.S. oil consumption--a higher level of dependence than at the time of the 1973-74 oil embargo. Furthermore, U.S. imports from the volatile Persian Gulf have increased inexorably.

We believe our nation cannot afford to exclude the ANWR coastal plain from efforts to find and develop the domestic energy resources so urgently needed to meet our future needs. The alternative is continued and ever-growing dependence on oil imports and increased risk of energy supply disruption of the type experienced in the 1970's.

Oil from the coastal plain would be transported by onshore pipeline to the existing Trans-Alaska Pipeline System (TAPS). Experience from TAPS and the Prudhoe Bay, Milne Point and Kuparuk oil field development proves that pipelines can be designed, constructed and operated on the North Slope to allow free migration of caribou and other wildlife.

ANWR is not a local issue. We believe that development of the ANWR coastal plain could result in significant economic benefits to all Americans. Revenue and employment generated by the increased exploration and development activity on the coastal plain would benefit not only the federal and Alaskan State governments, but the economy throughout the U.S., as equipment purchases are made and employment opportunities are created, just as other oil and gas operations in northern Alaska have generated.

America's energy security is at stake in the ANWR debate. If we are to reduce our heavy dependence on oil imports and provide our nation with a stable and dependable energy future, we must take steps now to increase domestic oil and gas production. We urge members of the Senate Energy and Natural Resources Committee to support Title IX of S. 341, legislation to assure access to the coastal plain area of ANWR.

MANUFACTURING
CREATES
AMERICA'S
STRENGTH

STATEMENT

ON BEHALF OF THE
NATIONAL ASSOCIATION OF MANUFACTURERS

ON
TITLE IX OF S. 341
OIL AND GAS LEASING IN THE ARCTIC NATIONAL WILDLIFE REFUGE
"THE NATIONAL ENERGY SECURITY ACT OF 1991"

SUBMITTED TO
THE ENERGY AND NATURAL RESOURCES COMMITTEE

UNITED STATES SENATE

MARCH 12, 1991

NAM

National Association of Manufacturers
1331 Pennsylvania Avenue, NW, Suite 1500 — North Lobby
Washington, DC 20004-1703 (202) 637-3000

The National Association of Manufacturers is a voluntary business association of more than 13,500 member companies and subsidiaries, large and small, located in every state. Members range in size from the very large to the more than 9,000 smaller manufacturing firms, each with fewer than 500 employees. NAM member companies employ 85 percent of all workers in manufacturing and produce more than 80 percent of the nation's manufactured goods. NAM is affiliated with an additional 158,000 businesses through its Associations Council and the National Industrial Council.

Executive Summary

NAM supports action to open the coastal plain of Alaska's Arctic National Wildlife Refuge (ANWR) to exploration and development. The strength and general welfare of the United States depend on the continued availability and development of adequate and secure supplies of energy at competitive prices to sustain economic growth. A critical step in ensuring this supply is to permit the leasing and exploration of ANWR's coastal plain.

History has shown that ANWR development and environmental protection need not be in conflict. More than 20 years of development in northern Alaska and dramatic technological change have proved we can have both.

Recent trends in the oil and gas sector reflect a rising U.S. dependence on imported oil. Imports have increased to nearly 50 percent since 1989 and are expected to top 60 percent by the year 2000 unless domestic resources can be utilized.

Such heavy reliance on oil imports could further weaken the U.S. economy. Even once Congress does act to open ANWR's enormous energy potential, it may take as long as 10 to 15 years before its oil and natural gas can reach the open market. Therefore, it makes sense to act now to open ANWR.

In addition to the energy benefits, development in ANWR could yield a net national economic benefit of more than $325 billion. These benefits would occur in more than 730,000 new jobs, lower balance of trade deficits and increased tax revenues to all government levels. These, as well as other economic benefits, would reach all 50 states. Development of Alaskan resources is not just an Alaskan benefit.

Recently, the Department of Interior significantly increased its estimated probability of discovering economically recoverable oil from 19 to 46 percent. The estimated amount of recoverable oil was also increased from 3.23 to 3.57 billion barrels.

NAM applauds the Senate Energy and Natural Resources Committee for including ANWR development in S. 341, the "National Energy Security Act of 1991." NAM also supports H.R. 759, introduced by Rep. Don Young (R-AK), and S. 109, introduced by Sen. Frank Murkowski (R-AK), as well as ANWR provisions contained in the administration's National Energy Strategy. All of these measures would allow oil and gas exploration, development and production on the coastal plain in an environmentally sound manner.

The decision we make today on ANWR will help to determine how vulnerable we are to imported oil in the near future. NAM, therefore, urges you to support legislation allowing the United States to explore for resources that could reduce growing foreign dependence for decades.

STATEMENT

ON BEHALF OF THE
NATIONAL ASSOCIATION OF MANUFACTURERS

ON
TITLE IX OF S. 341
OIL AND GAS LEASING IN THE ARCTIC NATIONAL WILDLIFE REFUGE
"THE NATIONAL ENERGY SECURITY ACT OF 1991"

SUBMITTED TO
THE ENERGY AND NATURAL RESOURCES COMMITTEE

UNITED STATES SENATE

MARCH 12, 1991

This statement is submitted on behalf of the National Association of Manufacturers (NAM) in support of the committee's hearing on the Arctic National Wildlife Refuge (ANWR). NAM supports legislative action that would open up the coastal plain of ANWR in an environmentally sound manner for oil and gas exploration, development and production.

NAM believes that public lands should not be closed to resource development in the absence of compelling national interest that overrides the need for a secure domestic energy and natural resource supply. Policymakers need to know what role ANWR can play in the nation's energy future in order to establish a long-term energy strategy.

INCREASED DEPENDENCE ON FOREIGN OIL

Today, America imports about half of the oil needed to meet a growing market demand. And, half of these imports come from the Persian Gulf area. It is estimated that U.S. foreign oil dependence could top 60 percent by the next decade unless domestic sources are utilized.

Production from current U.S. reserves is expected to decline considerably from the present 7.4-million barrels of oil per day (bpd) to less than 3-million bpd in the late 1990s. To compensate for this loss of production, new discoveries of domestic oil must be developed or imports will increase. Much of this decline will be attributable to decreased Alaskan production, which supplies 25 percent of the total U.S. production.

ENVIRONMENTAL CONCERNS

History has shown that ANWR development and environmental protection need not be in conflict. More than 20 years of development in northern Alaska and dramatic technological change have proved we can have both.

The ANWR coastal plain is 1.5 million acres of virtually uninhabited land, comprising only 8 percent of the total refuge. Within the coastal plain, only a small portion of acreage would actually be touched by exploration and production activities.

Wildlife habitats, environmental values and the petroleum industry can and do coexist. Prudhoe Bay serves as an example. When the Prudhoe Bay oil field was developed in the mid-1970s, regulatory agencies acted cautiously and studies were conducted to determine the effects on the Central Arctic caribou herd. In fact, the results of the studies and the tools implemented to prevent damage to the Central Arctic herd were quite positive. The herd has increased at a rate of 12-18 percent per year over the past decade. At more than 13,000, it numbers at least four times what it did in 1975 before most of the Prudhoe Bay development activity began.

The positive results from Prudhoe Bay and other similar experiences from northern Europe and the Soviet Union prove that herds can exist in the presence of industrial development, including oil fields and railroads.

ECONOMIC BENEFITS

ANWR development would provide significant direct and indirect macroeconomic benefits for the U.S economy by expanding the nation's productive potential. A recent economic impact study on ANWR development prepared by the WEFA Group concluded that increased domestic oil supplies reduce U.S. imports, thus leading to lower world oil prices. Lower resource prices increase the overall productivity of the economy and reduce outflow of U.S. capital.

The study also estimates that ANWR development would raise U.S. GNP by more than $50.4 billion by the year 2005 and create more than 730,000 new jobs around the country. ANWR development would benefit not just Alaska, but all 50 states as well as each level of government.

TRANS-ALASKA PIPELINE ENHANCES COMPETITIVENESS OF THE ANWR RESOURCES

When considering development of ANWR, the Trans-Alaska Pipeline System (TAPS) is an asset of enormous value that should not be ignored. This system, completed in 1977 and costing approximately 10 billion dollars, is already in place. The close proximity of TAPS to the ANWR region only enhances the resources potential for this area.

Since the cost of producing petroleum resources at any site includes development and transportation, the availability of TAPS capacity to transport potential North Slope production at ANWR and elsewhere represents a significant cost advantage versus a site where a more expensive transportation option is required.

This cost advantage resulting from the availability of relatively inexpensive TAPS capacity means that fewer resources need to be expended to produce the petroleum resources in ANWR than at a comparable site lacking in-place transportation facilities.

Most importantly, if no new large oil fields are developed on the North Slope, the TAPS will likely shut down in 2009. At that time, the flow of oil from currently producing fields in the region will decline below the minimum throughput rate of the pipeline. Once the pipeline is taken out of service, the cost of any future production on the North Slope would be prohibitive.

CONCLUSION

As important as ANWR is, it's only one piece of a large energy puzzle. ANWR could help reduce foreign imports and provide for energy needs well into the 21st century. We must be able to plan for future needs, and ANWR can play a role in meeting these needs.

NAM applauds the Senate Energy and Natural Resources Committee for including ANWR leasing and development in S. 341, the "National Energy Security Act of 1991." NAM also supports H.R. 759, introduced by Rep. Don Young (R-AK), and S. 109, introduced by Sen. Frank Murkowski (R-AK), as well as ANWR provisions contained in the administration's National Energy Strategy. All of these measures would allow oil and gas exploration, development and production on the coastal plain in an environmentally sound manner.

NAM believes that public lands should not be closed to or restricted from resource development and multiple uses in the absence of compelling national interests that override the need for adequate domestic oil, natural gas and other valuable resources. Before areas are set aside for exclusive uses, every effort should be made to determine the availability of materials and other resources on the proposed set asides, and access should be assured to explore and develop the area's resources.

NAM also believes that the development of domestic energy resources is the best hope to reduce America's energy vulnerability. Continued voluntary conservation of energy in all consuming segments is essential and should be constantly improved. Yet, while energy efficiency is an important objective, efficiency alone cannot solve our overdependence on foreign oil or provide for our future energy needs.

U.S. energy policy must reflect a long-term strategy. ANWR can provide critical energy supplies for decades, allowing time to develop new energy resources. Congress must act now to unleash ANWR's resource potential and establish a secure energy future for all Americans.

Thank you for the opportunity to express our views.

STATEMENT
on
THE NATIONAL ENERGY SECURITY ACT OF 1991, S. 341
for submission to the
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
for the
U.S. Chamber of Commerce
by
Jeffrey H. Joseph*
March 12, 1991

The U.S. Chamber of Commerce appreciates this opportunity to express its views on Title VIII of the National Energy Security Act of 1991. The Chamber supports an environmentally responsible, competitive oil and gas leasing program for the coastal plain of the Arctic National Wildlife Refuge (ANWR) because it is the nation's most promising onshore frontier for major oil and gas prospects. The U.S. Department of the Interior (DOI) estimates a 46 percent probability that the coastal plain contains economically recoverable oil and gas reserves, possibly as high as 9.2 billion barrels of oil and 64 trillion cubic feet of natural gas. At a time when domestic oil production is falling, and both oil demand and imports are rising, the nation's energy policy must emphasize domestic production.

The Chamber brings a unique perspective to the national energy debate as the only national organization that represents producers, distributors, and users of energy. Our principal concern is the continued economic viability of the business community. Access to secure, affordable supplies of energy is essential; an energy policy that does not accomplish this will increase costs in all business sectors and further undermine the competitiveness of U.S. products in global markets. In addition, several members of the Chamber staff have visited the North Slope and ANWR to see and learn first-hand about the oil and gas development in this fragile ecosystem.

Fewer than 15,000 acres -- less than one-tenth of one percent of the total refuge -- would be affected by oil and gas exploration and development. If oil and gas can be recovered, this additional energy production would be sure to:

---

* Jeffrey H. Joseph is Vice President, Domestic Policy

- strengthen the national economy by increasing Gross National Product (GNP) and the level of employment;
- reduce the nation's dependence on foreign oil supplies;
- reduce the nation's balance-of-trade deficit;
- provide a steady, significant, and greatly needed source of income to the federal government; and
- extend the lifetime of all producing areas on the North Slope.

Evidence Indicates Vast Oil and Gas Reserves

In April, 1987, DOI provided Congress with an analysis of the oil and gas resources beneath the 1.5 million-acre coastal plain of the 19 million-acre ANWR. Congress requested this assessment in Section 1002 of the Alaska National Interest Lands Conservation Act (ANILCA) of 1980. DOI reported that the estimated volume of recoverable oil in the coastal plain ranged from 600 million to 9.2 billion barrels of oil, with a mean estimate of 3.2 billion barrels. The marginal probability of discovering economically recoverable oil was placed at 19 percent.

In June, 1990, DOI's Bureau of Land Management (BLM) initiated a review of geological and geophysical data developed after 1987 to determine whether the estimates of recoverable oil in the coastal plain were still accurate. New information used in the reassessment included geological data from four wells drilled near the coastal plain, reprocessed geophysical data collected from the coastal plain, and some additional seismic data from offshore areas near the coastal plain. In February, 1991, BLM released its findings, which included:

- the marginal probability of the potential for oil recovery increased from 19 percent to 46 percent; and
- the mean resource estimate of economically recoverable oil increased from 3.23 to 3.57 billion barrels.

A 46 percent chance of discovering economically recoverable oil is considered excellent odds in the oil industry. Historically, there is a two percent chance that a wildcat well -- that is, a well drilled in an area where no economically producible amounts of oil have been discovered -- will result in a major discovery. Access to the coastal plain for exploratory drilling must be granted in order to prove the validity of the reserve estimates.

ANWR Production will Provide a Necessary Boost to the National Economy

Energy production on the coastal plain will benefit the U.S. economy by increasing demand for oil-related goods and services throughout the country. History proves that North Slope production created additional business in every state for the thousands of firms providing goods and services used in oil and gas development. Records from the construction of the Trans America Pipeline System (TAPS) and the development of the Prudhoe Bay and other North Slope fields (Kuparuk, Milne Point, Lisburne, and Endicott) indicate a cumulative expenditure of more than $36 billion for oil and gas facilities. Orders for manufactured goods included compressors from New York; steel from Pennsylvania and Oregon; pumps from Kansas; pipe from Alabama, Colorado and Texas; housing structures from Washington; blankets from North Carolina; carpeting from South Carolina; high technology instruments from New Hampshire; and telecommunications equipment from Hawaii. In addition, many states provided extensive technical services, including California, Texas, Louisiana, New Mexico, and Wyoming.

According to an analysis recently conducted by Wharton Econometric Forecasting Associates (WEFA), coastal plain development will raise U.S. GNP by $50.4 billion by 2005, and create an additional 735,000 jobs. The principal economic impacts of ANWR development are summarized in Table 1 (next page).

Table 1

Major U.S. Economic Effects of Coastal Plain Development

	1995	2000	2005	2010
Increase in GNP ($1988, billion)	4.7	36.1	50.4	22.4
Percent Change in Price Level	0.0	0.0	-0.1	-0.3
Change in Employment Level	56,000	410,000	735,000	372,000
By Sector: Manufacturing	21,000	90,000	128,000	45,000
Mining	1,000	50,000	84,000	55,000
Trade	11,000	122,000	225,000	78,000
Services	6,000	64,000	145,000	90,000
Construction	15,000	67,000	135,000	107,000
Percent Change in Industrial Production	0.1	0.7	0.8	0.2
By Sector: Mining	0.3	4.3	5.8	2.9
Manufacturing	0.1	0.5	0.5	0.1

Source: "The Economic Impact of ANWR Development," prepared by The WEFA Group, May 1990.

Table 2 (next page) breaks down the maximum increase of 735,000 jobs created in 2005 on a state-by-state basis. Every state is expected to benefit from increased energy production on the coastal plain.

Development of Coastal Plain will Reduce U.S. Dependence on Foreign Oil

Present domestic energy policy is only leading this country toward ever-greater reliance on foreign oil. Domestic crude production has declined 21 percent since 1973, to 7.3 million barrels per day (mb/d) last year. In 1990 alone, production fell 0.2 mb/d in the lower-48 states, and 0.1 mb/d in Alaska. The U.S. Department of Energy (DOE) predicts that production will continue to decline, averaging no more than 4.1 to 5.6 mb/d by 2010.

The most rapid decline is expected to be in Alaskan production, which now accounts for nearly 25 percent of total domestic crude oil production. Alaskan North Slope oil has passed its peak levels. The Prudhoe Bay field, the largest in the area with an estimated 12 billion barrels of economically recoverable oil and gas-related liquids, entered its decline phase

Table 2

Estimated Jobs Created by Peak ANWR Development in 2005

Alaska[1]	12,795	Montana	2,126
Alabama	10,392	North Carolina	19,389
Arkansas	5,464	North Dakota	1,800
Arizona	10,447	Nebraska	4,006
California	79,793	New Hampshire	3,898
Colorado	10,577	New Jersey	22,046
Connecticut	10,989	New Mexico	4,669
Delaware	2,032	Nevada	4,275
District of Columbia	2,516	New York	47,624
Florida	33,878	Ohio	31,842
Georgia	18,374	Oklahoma	11,268
Hawaii	2,702	Oregon	6,885
Idaho	2,369	Pennsylvania	34,279
Iowa	6,662	Rhode Island	2,919
Illinois	33,375	South Carolina	9,421
Indiana	15,622	South Dakota	1,771
Kansas	7,183	Tennessee	13,394
Kentucky	12,247	Texas	60,168
Louisiana	14,846	Utah	4,580
Massachusetts	20,260	Virginia	19,269
Maryland	13,912	Vermont	1,740
Maine	3,450	Washington	12,157
Michigan	25,014	Wisconsin	13,814
Minnesota	13,489	West Virginia	7,043
Missouri	14,138	Wyoming	2,958
Mississippi	5,918		

---

[1] Alaska is expected to reach its peak of 38,265 jobs in 2000.

Source: "The Economic Impact of ANWR Development," prepared by The WEFA Group, May 1990.

in 1989. Production is expected to fall from its present level of 1.7 mb/d to 0.25 mb/d in 2010. Production from the remaining primary fields on the North Slope is expected to begin its decline in the early 1990s.

As a result of the decline in domestic production, our dependence on foreign oil rose from 27 percent to nearly 50 percent during the past five years; our dependence on OPEC oil alone has grown from 12 percent to more than 26 percent. According to DOE, we may be importing as much as 54 to 67 percent of our oil needs by 2010.

Using DOI's estimate of 3.57 billion barrels of recoverable oil, production from the coastal plain could reach nearly 0.7 mb/d. Should the amount of recoverable oil be as great as 9.2 billion barrels, the coastal plain has the potential for producing more than 1.0 million barrels of oil daily for at least 20 years. The resulting decline in the nation's demand for oil imports is comparable to the import reduction that would be obtained by completely eliminating oil use in all residential and commercial buildings during those years.

Oil Imports and the Trade Deficit

According to the U.S. Department of Commerce, imported oil accounted for nearly one half of the $108 billion U.S. trade deficit during 1990. For every $1.00 price increase for a barrel of oil, the trade deficit increases by $2.7 billion annually. The price paid for imported oil is an enormous drain on the national economy. Interest rates are higher than they would otherwise be, curbing investment opportunities and leading to the export of both jobs and capital.

Increased Domestic Production will Raise Federal Revenues

Revenues generated by development of the coastal plain will benefit the U.S. government. If leasing is permitted, DOE estimates that as much as $6.5 billion in federal revenue could be generated from bonus bids through the sale of leases, with an additional $120 billion accrued from production royalties and lease rentals over a 30 year period. (These figures are based on finding 9.2 billion barrels of recoverable oil, with a reference price of $25.50 per barrel.)

Coastal Plain Production will Extend the Lifetimes of all Fields on the North Slope

According to a March, 1991 study by DOE, TAPS will likely be shut down in 2009, the year the flow of oil from Prudhoe Bay falls below the minimum 0.3 mb/d necessary to keep the pipeline working. In the absence of production from the coastal plain, then, we risk locking up all the remaining oil in Alaska.

Coastal Plain Development Can and Must be Done in an Environmentally Sound Manner

The coastal plain is prized not only for its oil and gas potential, but also for its aesthetic and wildlife values. The petroleum industry record in developing the North Slope fields shows that oil operations can be, and are being done, in an environmentally sound manner. For example, seasonal construction restrictions are observed to protect wildlife, temporary ice rather than permanent gravel roads are used to avoid both wildlife and habitat disturbance, and elevated and ramped pipelines are used to permit the passage of wild animals.

During development of the Prudhoe Bay field in the mid-1970s, studies were conducted to determine the effects of development on the Central Arctic Caribou herd. There were concerns regarding whether the caribou, accustomed to open tundra, would be able to negotiate roadways, raised pipelines, and vehicle traffic. Because of the great care taken to protect wildlife habitat, the population of the herd has increased from 3,000 in 1970 to approximately 18,000 today.

In addition, the oil industry is taking extreme precaution to protect against oil spills. Prior to the Exxon Valdez spill in 1989, tankers were escorted by pilot boat through a narrows approximately two hours from Valdez, and then left on their own. Today, tankers are escorted to open ocean (a journey of eight hours) by two oceangoing emergency vessels, each capable of towing a fully loaded tanker. Alyeska, the consortium of oil companies that own and operate TAPS, now has enough equipment, including 30 miles of booms and five barges, to skim 25,000 barrels of oil per hour off the ocean. The oil industry believes that with this equipment, the entire Valdez spill could have been cleaned up in 10 hours.

Technologies the industry developed in the Prudhoe Bay region would make producing oil on the coastal plain compatible with the environment. One of the key improvements in development technology has been the reduction in the amount of land needed to support a drilling operation. All facilities at Prudhoe Bay must be built on gravel pads to insulate the underlying permafrost and provide secure foundations for the structures. Through the use of such advanced technologies as directional drilling, dozens of wells can be drilled from the same pad with as little as 35 feet separating the wells. In special cases, wells have been drilled even closer together. From the centralized drilling pads, wells fan out at angles from the surface location to reach remote parts of the underground oil reservoir.

The regulatory framework for oil development is complex and comprehensive. For both large and small projects, site-specific environmental studies are conducted prior to construction. Modifications to project design are often made in response to environmental concerns, and many stipulations are attached to permits to ensure the facility is properly operated. Furthermore, both construction and operation are closely monitored by federal, state, and local agencies.

Conclusion

The progression of events from leasing, to development, to production of the coastal plain is expected to take 10 to 15 years. This long lead time is a function of the remoteness of the region, concerns for environmental protection, and the regulatory process. Because of this extended lead time and the need to evaluate the coastal plain's resources more thoroughly, exploration must begin as soon as possible in order to compensate appropriately for the ongoing decline in domestic production from non-ANWR sources.

The Chamber urges the Committee to report national energy strategy legislation that will permit the exploration and development of the coastal plain's oil and gas resources in an expeditious and environmentally sound manner.

TESTIMONY OF
NORTH SLOPE BOROUGH, ALASKA
BEFORE THE SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

These are the views of the North Slope Borough, Alaska, on S. 341, The National Energy Security Act. The Borough is the largest municipal government jurisdiction in the United States, and its boundaries include the Arctic National Wildlife Refuge (ANWR) (see map, attached). The Borough testified before this Committee on an ANWR Coastal Plain leasing proposal in the 100th Congress.

We use this occasion to present our views on two titles of S. 341. One is Title VIII, which provides for the sharing of revenues related to oil and gas exploration and development of the Outer Continental Shelf (OCS) with impacted coastal states. The second is Title IX, which would open the ANWR Coastal Plain to competitive oil and gas leasing.

I. OCS Revenue Sharing

The North Slope Borough is bordered by the Beaufort and Chukchi Seas, both of which have sustained significant OCS lease activity. For this reason, the Borough is encouraged to see that this Committee recognizes the impact such activities have upon coastal communities.

The communities of the North Slope, not the State of Alaska, will bear the brunt of shoreside costs of OCS exploration and development. These burdens come in different forms. There are the costs of providing necessary municipal services. The North Slope Borough consists primarily of traditional Inupiat whaling villages where all municipal services and infrastructures were installed at Borough expense - primarily with bonded debt proceeds.

Moreover, there are impacts which cannot be quantified as easily. The sea and its treasures are the focus of our way of life. It is, as we say, our Garden. When offshore oil and gas exploration occurs, our Garden is put at risk, and our subsistence resources are jeopardized. This can result in acute social dislocation for many villagers. We in Alaska are all too familiar with the potential for harm to the sea which comes with the exploration and development of oil and gas. For bearing these and other costs, it is only fair that some portion of the rewards be used to offset the resultant costs to local government.

While we are pleased that the Committee proposes a return to the OCS revenue sharing which Congress abandoned 10 years ago, at the same time, we cannot help but worry about what we consider a serious flaw in the provision. Title VIII directs that 37.5% of all OCS revenues be distributed to affected coastal states. Although the bill also directs that the monies be used to address the impacts of OCS activities on local communities, there are no strict requirements that the monies be shared with the impacted local governments. It is essentially left to the states to decide.

The North Slope Borough is all too familiar with the problems which arise from such a scheme. The state and local governments inherently have different viewpoints and priorities as to where such monies should go. In the past, the Borough has had to go so far as to bring suit against the State of Alaska in order to receive a share of mineral leasing revenues from the National Petroleum Reserve-Alaska distributed under a Federal law similar to Title VIII. In other words, Federal sharing of OCS revenues with the states virtually guarantees that a Federal policy of sharing with the local governments really affected, and who incur the most direct costs, will not occur.

The North Slope Borough favors adoption of an OCS revenue sharing scheme like that offered in Senator Stevens' (R.-AK) bill, S. 39. That bill creates a statutory entitlement in impacted local governments to a portion of relevant OCS revenues. Such a system would ensure that the revenues go where needed without unnecessarily giving rise to conflicts with the states.

II. ANWR Oil and Gas Leasing

Title IX would open the ANWR Coastal Plain to competitive oil and gas leasing. If the estimates for the Coastal Plain's reserves prove accurate, we can expect development and production activities to start after the year 2000.

The North Slope Borough has previously testified before this Committee in support of exploration and development of the Coastal Plain, so long as it is not done in a manner inconsistent with the subsistence and other needs and interests of the people of the North Slope, and with a sensitivity toward the inland and offshore environment. One of the most important ways to address these needs would be a mechanism for providing impact aid to the North Slope communities.

If OCS revenue sharing with local entities were enacted, impact aid might not be required, depending on the relative timing of Beaufort/Chukchi lease sales and an ANWR leasing decision. However, it is certain that the need for all local governmental services will increase exponentially if and when the Congress opens ANWR. The Borough's costs and revenues to provide these services have been carefully balanced to reflect the reality of no growth, or of continued decline. But our funding sources will not be sufficient if Congress enacts legislation to open ANWR to oil and gas leasing. Unless the federal government shifts radically its past practice of ignoring municipal cost-recovery in permit decision-making, while finding a way to keep its permittees and non-permittees away from municipal facilities and services, (and we know of none), the demands for municipal services by visiting dignitaries, the oil industry, State and Federal employees, consultants, local residents and drifters, will fall inevitably on the North Slope Borough government, not Arctic Slope Regional Corporation, Kaktovik Inupiat Corporation, or the State of Alaska.

Who should pay? Well, the Borough has paid plenty to build and maintain Kaktovik, the most likely base for ANWR development. Federal agencies already enjoy the benefits of that subsidy. But the NSB government has calculated its budget, and made provision for construction, operation, maintenance, and replacement, based on the current and projected level of income, debt, and growth without ANWR.

S. 341 proposes that Congress and the State each keep fifty percent of the revenues from ANWR, cutting off the Borough's entitlement under the Refuge Revenue Sharing Act. The influx of people who have been and will be studying, planning for, and carrying out the exploration and development of these Federal lands would swamp Kaktovik, and put serious pressure on the Borough's budget and planning capabilities.

The Borough feels strongly that the Congress should assist it in providing local government response. These are federally created impacts, and they are occurring already. They are, in part, a Federal responsibility. The exploration and development of ANWR has been and will be a major Federal action.

In the past, Congress has always provided impact aid in major Federal onshore mineral leasing programs. In the OCS Lands Act, as in Title VIII, this Committee has already recognized the necessity of impact aid, drawing upon the coastal energy impact program, 16 U.S.C. § 1456a. Most important, the Refuge Revenue Sharing Act itself embodies impact aid. 16 U.S.C. § 742s(c). In the Federal Coal Leasing Act Amendments of 1976, Congress saw to it that local communities on the West Slope of Colorado received $150,000,000 in Federal oil shale lease revenues to abate impacts of Federal oil shale developments that failed.

Other precedents include: (1) Section 35 of the Mineral Leasing Act; (2) Section 107 of the Naval Petroleum Reserve Production Act of 1976, Pub. L. No. 94-258, and the 1980 NPR-A Leasing Amendments passed as part of a DOI Appropriations Act, 42 U.S.C. § 6508; (3) Section 317(c) of FLPMA; (4) MX Missile and East Coast Trident Programs, 95 Stat. 1382, 94 Stat. 1775; (5) establishment, realignment or closure of military installations, 10 U.S.C. § 2391(b); (6) Surface Mining Control and Reclamation Act, 30 U.S.C. §§ 1233, 1236(d); (7) financial assistance to educational agencies in areas affected by Federal activities, Pub. L. No. 91-874 and Title II of Pub. L. No. 91-815.

The Borough and other communities can demonstrate the need for such aid. We attach documentation of need previously submitted to House Committees. The Borough is the sole municipal services provider for its cities and villages, including Kaktovik. Most of you take these things for granted until you require them, or the service involved breaks down. Kaktovik's municipal corporate charter grants only recreation powers. The Borough funds, staffs, and maintains all utilities, public safety, fire, search and rescue, and health services in the village. In addition, the NSB government has responsibility for education, planning, zoning and permitting.

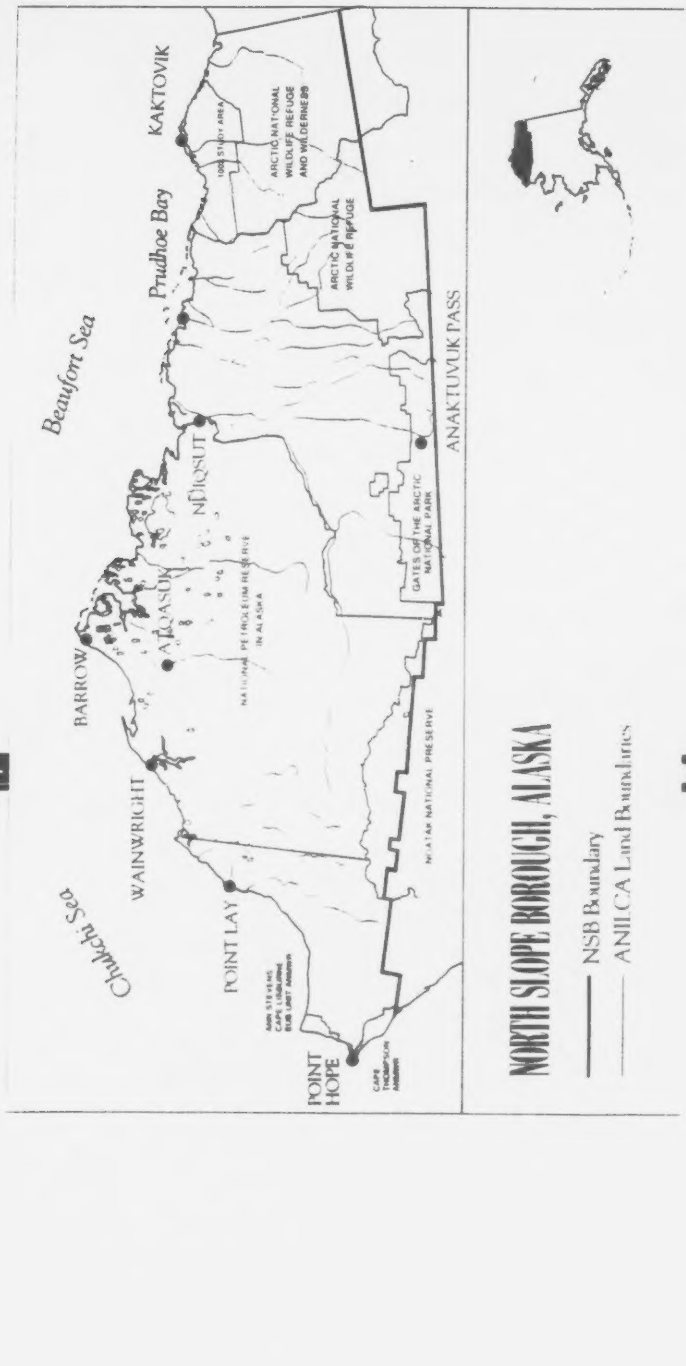
During the development stages of an oil field, the property tax revenue received by taxing exploration and drilling equipment is minimal, when compared to in-place production facilities and infrastructures. However, many impacts on municipal services and facilities are occurring and will occur prior to the development or production stages (if any) of ANWR. Some measure of impact aid is necessary during this time gap.

There are not any immediately available funding sources open to the Borough. Native and other private corporations' dividends are not now and never have been taxable by the State, much less available to the Borough government to pay for municipal services. User and permit fees have never recovered costs in our area, where construction and maintenance expenditures are astronomical, and the user base minute.

The Borough's tax revenues will soon be declining. The assessed value of present Prudhoe-area facilities will be largely depreciated by 2005. The Borough has voluntarily accelerated its bond repayment schedules; the current bond schedule will be paid off by 2000. This accelerated repayment schedule attests to the Borough's fiscal responsibility. This decision was made to tie repayment to the depreciation of the Prudhoe-oil production assets, and to assure that our major debts would not remain when the largest source of revenue disappeared. Unfortunately, the Borough's efforts to retire its debt and thereby act in a fiscally responsible manner comes at a time of a decrease of its ability to raise tax revenue. By State law, the NSB's current property tax mill rate of 18.37 must drop to approximately 4 mills due to a State imposed ceiling on the Borough's ability to tax expressly for operations and maintenance. That drop in mill rate will reduce the Borough's tax income in 2000 by $175 million (77%), just when ANWR development, if any, may be in sight.

The NSB has saved or invested some Prudhoe Bay-related proceeds for a variety of future outlays. For example, the Borough has a Permanent Fund, which will be a source of income for operation and maintenance of basic services when oil property assets are depreciated (2000). However, those funds are not available, much less adequate, to underwrite the great expansion and upgrade of facilities and services that an ANWR oil and gas leasing program will impose prior to development and production.

If ANWR is to be opened to exploration and development, then the North Slope Borough needs and is entitled to some form of impact aid. This activity will be taking place within its boundaries and the North Slope Borough, not the Federal government, not the State of Alaska, and not the Native corporations, will bear the accompanying burdens and costs.



NORTH SLOPE BOROUGH, ALASKA

Beaufort Sea
Chukchi Sea
BARROW
WAINWRIGHT
POINT LAY
POINT HOPE
ATQASUK
NUIQSUT
Prudhoe Bay
KAKTOVIK
ANAKTUVUK PASS
1002 STUDY AREA
ARCTIC NATIONAL WILDLIFE REFUGE AND WILDERNESS
ARCTIC NATIONAL WILDLIFE REFUGE
GATES OF THE ARCTIC NATIONAL PARK
NATIONAL PETROLEUM RESERVE IN ALASKA
NOATAK NATIONAL PRESERVE
ANN STEVENS CAPE LISBURNE SUB UNIT AKMNWR
CAPE THOMPSON AKMNWR
NSB Boundary
ANILCA Land Boundaries

PROPOSED PROJECTS TO BE FUNDED BY IMPACT AID GRANTS

Our experience with Prudhoe Bay-area unit developments, and with drilling programs in the NPR-A, the Barrow Gas Fields, and at Kaktovik, tell us that the following public facilities and services will be demanded by ANWR exploration and development:

1. Center at Kaktovik for victims of substance abusers. The pressures of actual and impending Federal developments in the Eastern Beaufort, plus the loss of subsistence opportunities, have contributed to a loss of identity and caused substance abuse at Kaktovik. There is a pressing need for a facility at Kaktovik for those victimized by substance abuse, who need to be separated from the abusers and counselled.

2. Planning, zoning, and permitting. This is necessary at the pre-leasing and pre-exploration phases of ANWR and KIC land development, and also by the need to plan for and design Borough-provided facilities and services.

ANWR may require one of the most intensive planning, zoning, permitting, and platting exercises ever performed in the Borough. The Borough will perform planning and platting responsibilities at Kaktovik, where we assume industry and Government personnel will find it most efficient to locate during the pre-exploration phase of ANWR development. We would expect to hire and place at Kaktovik a city planner, on the Borough payroll. Any industrial center at Kaktovik would have to be platted and located at a point separate from the existing Village.

Planning for ANWR development currently exceeds the abilities of the Borough Planning Department. The Borough requires at least one planner in Barrow, working full time on ANWR. Additionally, another full-time employee (FTE) is presently required for platting and mapping activities at Kaktovik and at any base camp(s) used by industry and Government during the pre-exploration phase.

3. Utilities. This includes electricity, water, sewer, and solid waste collection in Kaktovik and Deadhorse (Borough Service Area 10).

The Kaktovik power plant (oil-fired) is operating at or near capacity. There are no current plans for expansion. A request will be made to expand the facilities to meet demand for Kaktovik without regard to ANWR impact. ANWR would not only mean immediate expansion, but consideration of eventual replacement of the power generating facility with a natural gas-fired facility.

The potable water system is currently being upgraded and expanded to include additional water storage capability, water treatment capability, and washeteria facilities. These upgrades did not consider any additional local growth patterns beyond what exists or is projected today. A treatment facility would be needed. Local water sources could not provide enough water to meet demand. Sea water would need to be de-salinated for use as potable water.

The garbage and solid waste systems barely meet the needs of local residents now. There are no areas which could be used to build landfills and sewage lagoons or secondary treatment facilities for sewage.

Oil development could have serious consequences on the North Slope Borough's ability to retain qualified employees to continue to provide the services that are in demand. Wages at the local level are well below Davis/Bacon-type salaries. Most villagers would consider a job change solely on the basis of hourly wage, without regard to the stability provided by long-term municipal employment.

If significant development occurs in the immediate Kaktovik area and we would be required to provide these services on demand, the utilities system would have to be completely overhauled or replaced.

4. Public Safety, Fire, Search, and Rescue. Police and criminal justice responsibility and facilities at Kaktovik would be expanded during the pre-exploration stage. Current detention facilities are antiquated and inadequate for increased use. Two additional officers will be required as the substance abuse-related problems increase with the wealth and employment which current residents will experience, and that new residents will bring.

Local ordinances and State codes are very sparsely enforced because there is no local court or prosecutor. Requests for an additional District Attorney in Barrow and prisoner transfer costs will be presented.

If the Federal Government requires that ANWR-related Government and industry personnel must be based at Deadhorse or, perhaps more appropriately, the Kuparuk Industrial Center, no existing Native community there would be affected and police requirements would not change materially. Even if personnel are based at Prudhoe, the social problems that wealth, outsiders, and employment would bring to Kaktovik will remain. A conservative estimate of the added police personnel, housing, detention, and transportation demands at Kaktovik is: $1,0000,000 for facility expansion and personnel housing, plus $400,000 annually for personnel costs.

Fire problems hinge on whether more people or buildings are required. If pre-exploration-phase personnel are housed at

Kaktovik, those structures would probably have to be built. The high winds, dry climate, wood frame construction, and an absence of hydrants make fire-fighting facilities capital intensive. Firefighters are volunteers.

If there is full employment in the Village, then we would have to consider having a paid fire department in order to have adequate fire and emergency medical services coverage. We would need more firefighting equipment (i.e., 1,000 gpm fire pumper truck, large diameter hose, etc.) and a larger fire station to handle the increase in number and size of fires. We would need a better water supply to fill our fire trucks than we have at present. We would need a training center and additional training personnel to handle the demands posed by this increased activity.

Search and rescue services include air evacuation and search services that industry does not or cannot provide. Moreover, industry would not provide these services generally to those people who will be drawn to ANWR in the pre-exploration phases.

Industry has no capability for remote site medivac treatment. For example, during the seismic program on ANWR in 1984 to 1985, we provided a heart attack evacuation, a plane crash search and rescue, and several medivacs off the cat-trains.

Our aircraft are based only at Barrow. Currently, the ANWR area does not require aircraft and personnel permanently based in the eastern Borough. However, each year, our flight hours increase by thirty-five (35) percent, and our ability to commit additional flight time and resources to ANWR is marginal.

5. Wildlife Management. This includes the study, review, and monitoring of developments to minimize effects on subsistence resources, and access thereto. It also includes game management.

The planning process will be great and has already begun. The level of studies conducted in ANWR will increase markedly. The subsistence hunters will become more aware of the potential threats to their animals (and associated habitat) and will demand more Borough involvement.

Over the next few years the "planning" process (research plans, conduct of studies, review of technical reports, coordination meetings, etc.) will intensify. In order to define subsistence resources and provide for adequate local input into decisions affecting subsistence resources and access, the Borough will have to add five FTE's and open an office in Kaktovik. With associated equipment and travel costs, we conservatively estimate a first-year cost of $450,000, and at least $375,000 per year thereafter, until exploration begins.

6. Health and Social Services. The Borough's Department of Health and Social Services provides a well-equipped clinic, two community health aides, and health and social services programs at Kaktovik, but not at Prudhoe. Industry facilities are available on a trauma basis only to some Prudhoe area personnel not employed by the oil companies.

At Kaktovik, the Borough will have to implement vigorous education and prevention programs well before the construction phase: alcohol and drug prevention; youth activities; stress management; disease prevention; accident prevention.

As the population at Kaktovik increases, the health program will be upgraded with added staff and services. Three to four mid-level practitioners may be added, as the nature and amount of injuries, accidents, and health problems change. Personnel and travel expenses would be primary concerns under a minimal Kaktovik development scenario. If there were a large influx of industry, Government, and permanently-based personnel in or near Kaktovik -- a "worst case" scenario -- the delivery of health and social services would become a nightmare. The present clinic would need to be converted to a "family services" type facility, such as the Greist Center in Barrow, and most "service provider" programs in Barrow, such as Day Care and AWIC, would require a village-based satellite programs. Furthermore, a much larger clinic would need to be constructed to provide expanded routine, intensive, and emergency care.

TRANSPORTATION INSTITUTE

5201 Auth Way
Camp Springs, Maryland 20746
(301) 423-3335 (MD)
(202) 347-2590 (Wash., D.C.)
Telecopier (301) 423-0634

Pacific Coast Office
2505 2nd Avenue
Suite 720
Seattle, WA. 98121
(206) 443-1738

JAMES L. HENRY
President

LAWRENCE H. EVANS
Director, Domestic Marine Affairs

WILLIAM D. LAWRENCE
Director, Pacific Coast Operations

GERARD C. SNOW
Director, Government Affairs

BOARD OF DIRECTORS

HERBERT BRAND
Chairman

CAPTAIN LEO V. BERGER
President
Apex Marine Corporation

CARMINE J. BRACCO
Vice President
Bay Tankers, Inc.

J. WILLIAM CHARRIER, JR.
President
American Automar, Inc.

THOMAS B. CROWLEY
Chairman of the Board and
Chief Executive Officer
Crowley Maritime Corporation

PATRICK T. FAHEY
President and Chief Executive Officer
Delta Queen Steamboat Company

D. WARD FULLER
President and Chief Executive Officer
American Steamship Company

HARRISON R. GLENNON, JR.
President
Sea Mobility, Inc.

JACK GOLDSTEIN
President and Chief Executive Officer
OMI Corp.

RAN HETTENA
President
Maritime Overseas Corporation

ROBERT B. McMILLEN
President and Chief Executive Officer
Totem Ocean Trailer Express

RONALD C. RASMUS
President
Great Lakes Towing Company

DAVID J. TOLAN
Senior Vice President
Sea-Land Corporation

EDWARD P. WALSH
President
Waterman Steamship Corporation

STATEMENT
OF
JAMES L. HENRY
PRESIDENT
TRANSPORTATION INSTITUTE
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
U.S. SENATE
WASHINGTON, D.C.

MARCH 12, 1991

NATIONAL ENERGY POLICY FOCUSING ON ARCTIC NATIONAL WILDLIFE REFUGE AND STRATEGIC PETROLEUM RESERVE

. . . Working for a Strong American Maritime Capability

The Transportation Institute, a research and educational organization representing over 140 U.S.-flag vessel operators engaged in all forms of waterborne commerce in both the domestic and international trades, is supportive of congressional efforts to enact a comprehensive national energy policy. For too long, we have postponed formulation of such a policy as the mere essence of a national strategy has been debated. However, circumstances in the Persian Gulf have once again made the nation aware of the economic and national security vulnerability that it has imposed on itself as a result of the continuing dependence on foreign energy sources. Forging a comprehensive program that takes into consideration all of the essential components -- conservation, efficiency, production, reserves, and alternative energy sources -- is formidable. However, through the acceptance of a number of difficult choices the nation will achieve a strengthened economy and improved national security.

The U.S.-flag maritime industry is anxious to contribute to a sound energy program and looks forward to the enactment of a viable national policy which will prove beneficial to the American public and American industry. We are especially interested in two aspects of the current debate which would impact directly on the U.S. merchant marine -- Arctic National Wildlife Refuge and the Strategic Petroleum Reserve -- and urge the Committee to give favorable consideration to the inclusion of these elements in the energy package reported to the full Senate.

Recent events in the Persian Gulf are a stark reminder of the dangerous degree to which our nation continues to remain dependent on foreign sources of oil. At a State Department-sponsored energy conference last month, a consensus of expert opinion concluded that heavy U.S. dependence on Middle East oil will continue through the 1990s. Saudi Arabia, Iraq, the United Arab Emirates, Kuwait and Iran possess 65 percent of the world's known oil reserves and 90 percent of its extra oil production capacity. Meanwhile, U.S. oil production last year fell for the fifth consecutive year -- to its lowest level in 25 years. During the first half of 1990, the United States imported 50 percent of its total oil consumption with roughly 25 percent of its needs coming from the Persian Gulf. Projections contained in the administration's recently released National Energy Strategy affirm the nation's increased dependence unless a number of steps in both oil production and conservation areas are implemented. Such steps, are included in varying forms in both the National Energy Strategy (introduced last week as S. 570) and the comprehensive energy package (S. 341, the National Energy Security Act of 1991) sponsored by several members of this Committee and other legislative initiatives pending before the Congress, which if adopted, should assist the nation in lessening its dependence on foreign oil.

ARCTIC NATIONAL WILDLIFE REFUGE (ANWR)

The Transportation Institute believes that opening the coastal plain of the Arctic National Wildlife Refuge to exploration and subsequent environmentally sound development is one of the most important proposals put forth by either Legislative or Executive Branch policy-makers. Adding ANWR to America's oil reserves could help to prevent the threats to supply and severe price disruptions that rocked the petroleum markets last summer after the Iraqi invasion of Kuwait. Recently, the

Bureau of Land Management more than doubled its assessment of the marginal probability of oil discovery there from 19 to 46 percent, and increased the mean estimate of economically recoverable oil from 3.23 to 3.57 billion barrels. **In urging favorable consideration of ANWR development, the Transportation Institute's support is contingent upon an explicit provision that oil extracted from the Arctic National Wildlife Refuge be reserved for domestic consumption.** The maritime industry is grateful for the Committee's vote in the 101st Congress in support of such restrictions and is pleased that the Chairman has included this policy in S. 341 currently under review within the Committee.

A viable U.S.-flag tanker fleet is essential to the nation's economy and security during a national emergency. Last week, General H.T. Johnson, Commander of the U.S. Transportation Command, testifying before the Senate Armed Services Committee on the role of sealift to sustain military objectives in Operation Desert Shield/Storm observed that 4.2 million tons of refined petroleum products were moved as of 1 February, representing 99 percent of the fuel shipped to the Gulf. While these numbers appear impressive, it is important to heed General Johnson's warning that "as we move away from the threat of global war and focus our national strategy on the threat of fast-breaking regional conflict, we must maintain our ability to respond to wartime transportation requirements like those we've seen for Desert Shield/Storm while operating under the constraints of a peacetime economy. This fundamental shift in strategy places great pressure on our desire, as codified by the National Security Sealift Policy of 5 October 1989, to rely on the U.S. merchant marine for the majority of our defense sealift needs. If we consider peacetime economic pressures in light of the continued decline of the U.S. merchant marine, our ability to rely on U.S. commercial shipping may be eroding."

Today only 44 U.S.-flag tankers currently transport crude oil produced in Alaska to the lower 48 States. A decade ago, over 80 tankers were engaged in the Alaska oil trade and that number is expected to drop to less than 20 by the year 2000 if new sources are not developed on the north slope. Without an adequate tanker fleet, our nation's ability to produce the kind of outstanding military success we recently witnessed in the Persian Gulf will be severely limited. Ensuring a stable, consistent supply of cargo is the only way to guarantee the availability of these essential vessels and their trained civilian crews during times of emergency.

In terms of cost-effectiveness, there really isn't any viable alternative. Further contraction of the domestic tanker fleet will force many vessels into default, including those whose construction financing is guaranteed by the federal government. Additionally, if military planners cannot count on tankers from the private sector, they will have to acquire them for the Ready Reserve Force, with massive and continuous expenditures for maintenance and berthing, and no employed workforce to crew them.

Operation Desert Storm/Shield highlighted some of the difficulties in breaking out and mobilizing reserve vessels as a result of the decline in the nation's commercial shipping base. It is important to remember that the foreign-flag shipping upon which the Pentagon relied was available under extraordinary circumstances not likely to repeat themselves in the future. The build-up and deployment of forces in the Persian Gulf took place over the span of nearly half a year, during which not a single shot was fired. Further, the United States enjoyed a level of global unanimity and political support that was unprecedented. We cannot rely on these favorable conditions again. The U.S. must be prepared to "go it alone", as was determined by the findings of the presidentially appointed Commission on Merchant Marine and Defense in its 1988 report.

In addition to serving as a military asset, America reaps significant economic benefits from its tanker fleet as well. An active fleet is in a position to make payments on federally guaranteed loans. Employed tankers contribute substantial tax revenues to the Treasury, as do the seafarers working on the vessels. Their prosperity spreads to the ports on which they call, increasing shoreside employment and supporting related maritime industries. Reduced reliance on foreign oil would result in a parallel reduction in our balance-of-trade deficit. Safe, reliable U.S.-flag tanker service, combined with a dependable flow of oil as yielded by ANWR, would continue to provide stability to the domestic oil market.

During the debate over ANWR, a great deal of attention will be focused on the environmental impact. What has been frequently overlooked in the debate is the real choices facing the nation in arranging the transportation of petroleum products. Many of the environmental concerns in that area were addressed last year by the passage of the Oil Pollution Act of 1990. However, increased reliance on foreign sources of oil, necessitated by the lack of new production, or for that matter the export of domestically produced oil such as that to be found in ANWR, would subject our waterways and coastal areas to a parade of foreign-flag tankers. Many of these vessels don't come close to their U.S.-flag counterparts in safety and maintenance regulations, manning standards and technology, all of which could adversely impact the nation's environmental quality. Needless to say, none of these vessels would add one iota to our national security either. Environmental concerns alone dictate that it is wise policy to encourage U.S.-flag tanker operations whenever possible.

STRATEGIC PETROLEUM RESERVE

The Persian Gulf crisis reinforced to the nation the importance of the energy insurance policy encompassed in the Strategic Petroleum Reserve. As a result of its very existence, the nation was given a peace of mind that assisted it in weathering the energy storm resulting from the invasion of Kuwait. Regrettably, throughout the 1980s efforts to encourage a rapid SPR fill when oil prices were low were brushed aside in the wake of budgetary constraints. It was only in the last year that sufficient support was generated to allow for the enactment of legislation raising the target to one billion barrels. However, at the end of last year, the Reserve contained 585.7 million barrels of crude oil, far short of the newly established target.

As the Congress gives further attention to an expansion of the Reserve, the Transportation Institute urges favorable consideration to initiatives that will result in an increase fill to meet the one billion barrel target. **In this regard, we ask the Committee to resist any efforts to waive U.S. maritime policy in either the fill or drawdown of the Reserve.** The U.S. maritime industry, which in one breath is asked to serve as the nation's fourth arm of defense and sail into the Persian Gulf in harm's way, in the next breath is assaulted by the Administration through its blanket waiver of the Jones Act in the January drawdown of the Reserve. This action had the effect of giving heavily subsidized foreign-flag operators the same opportunities to bid for SPR oil transport as their U.S. counterparts, apparently with little or no thought given to the impact this would have on the U.S. tanker fleet, nor to the precedent it would establish should hostilities continue indefinitely. Preliminary estimates show the extent to which foreign vessels quickly entered the domestic trades when given the chance. Thirty-six percent of the drawdown movements were by tanker (mostly all foreign flag), two percent by barge and the remainder by pipeline.

The Transportation Institute is further alarmed that the Administration's legislative package (S. 570) to implement its National Energy Strategy calls for an exemption from "Federal contracting laws and regulations" in the event of a drawdown of a proposed Defense Petroleum Inventory to complement the Strategic Petroleum Reserve. While the U.S. maritime industry recognizes that there may be inadequate tonnage to meet all energy transport requirements, we maintain that there is no need to issue blanket waivers or statutory exemptions as they only serve to erode even further the ability of the U.S. fleet to meet its defense and economic obligations. In fact, in the past year an Energy Department, Customs Service and Maritime Administration agreement was ironed out to establish procedures to expedite waiver procedures of the cabotage statute in the event of a drawdown. Moreover, in early January John Easton, Assistant Secretary of Energy for International Affairs and Energy Emergencies, testified before the House Energy and Commerce Committee that the inter-agency agreement was adequate for handling an energy emergency. The Institute urges the Committee to reject any suggestions that maritime policy should be waived at the expense of energy policy.

CONCLUSION

The Transportation Institute believes that environmentally safe exploration and development of the Coastal Plain of the Arctic National Wildlife Refuge is strongly in the national interest, provided any oil produced is retained for domestic consumption. Anything less would be a betrayal of its promise as a key component of an overall energy strategy and would substantially weaken an already ailing merchant marine. We further believe that a petroleum reserve filled at complete capacity is the added insurance policy that will keep our economy running and military forces sustained.

A comprehensive energy policy should be multi-purposed serving the nation in varied ways. Participation in these programs as enunciated in long-established maritime policy will enable the U.S.-flag merchant fleet to contribute to both the nation's defense and economic securities. In his appearance last week before the Senate Armed Services Committee, General Hansford Johnson of the U.S. Transportation Command observed that "if rapid deployment prevented Saddam Hussein from moving his troops into Saudi Arabia, then mobility itself can be seen as a deterrent to military aggression." General Colin Powell, Chairman of the Joint Chiefs of Staff, took this thought a step further when he stated to the House Armed Services Committee on February 7: "Deterrence is only credible if we possess a robust means of power projection and the mobility to deploy and sustain our forces." A robust U.S.-flag merchant fleet as full participants in a national energy policy is a sure means to achieve this objective.

American Institute of Merchant Shipping
1000 16th Street, N.W., Suite 511, Washington, D.C. 20036-5705
Telephone (202) 775-4399 · FAX (202) 659-3795

March 21, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

Attached for your review is the statement submitted by Ernest J. Corrado, President of the American Institute of Merchant Shipping for the hearing record on S. 341, the "National Energy Security Act of 1991."

The American Institute of Merchant Shipping (AIMS) is a national trade association representing 24 U.S.-flag carriers which own or operate approximately eleven million deadweight tons of tankers, dry bulk carriers, containerships, and other oceangoing vessels engaged in the domestic and international trades of the United States.

As you know, Title IX of S. 341 contains provisions which authorize a competitive oil and gas leasing program for the Coastal Plain of the Arctic National Wildlife Refuge in Alaska (ANWR). AIMS, over many years, has supported this concept and the positive impact this legislation would have on the U.S. maritime industry as well as on the nation's broader energy and security needs.

Thank you for your attention to this portion of the record.

Sincerely,

Curry Ann Lawless

Curry Ann Lawless
Director of Legislative Affairs

Attachment

TESTIMONY OF

ERNEST J. CORRADO, PRESIDENT

AMERICAN INSTITUTE OF MERCHANT SHIPPING

SUBMITTED TO THE SENATE COMMITTEE ON ENERGY
AND
NATURAL RESOURCES

MARCH 12, 1991

The American Institute of Merchant Shipping (AIMS) appreciates the opportunity to submit this brief statement for the hearing record on S. 341, the "National Energy Security Act of 1991," Title IX concerning provisions which authorize a competitive oil and gas leasing program for the Coastal Plain of the Arctic National Wildlife Refuge in Alaska (ANWR). We particularly wish to express our appreciation to the committee members for proceeding with these important hearings at this critical time.

The American Institute of Merchant Shipping (AIMS) is a national trade association representing 24 U.S.-flag carriers which own or operate approximately eleven million deadweight tons of tankers, dry bulk carriers, containerships, and other oceangoing vessels engaged in the domestic and international trades of the United States. As a representative of the vast majority of tankers involved in the carriage of crude oil from Alaska's North Slope (ANS), we strongly support S. 341 to authorize leasing, in an expeditious and environmentally sound manner, the public lands within the Coastal Plain of ANWR for oil and gas exploration, development, and production.

Our statement concerns the positive impact this legislation would have on the U.S. maritime industry as well as on the nation's broader energy and security needs. Now, more than ever before, the development of the resources of the Coastal Plain of Alaska's Arctic National Wildlife Refuge is a necessary and reasonable step toward national energy security. The passage of the "Oil

Pollution Act of 1990," OPA'90, (P.L. 101-380), reaching all aspects of the marine transportation of petroleum products, clears the way to the greatest extent possible by legislation, for protection of the marine environment. Today no logical reason exists to "lock up" Alaskan oil reserves because of environmental concerns.

Therefore, in compliance with OPA '90 and other federal statutes as well as statutes at the state level, now is the time to secure all of the benefits of responsible domestic oil production and dependable coastwise transportation of U.S. crude oil.

Opening up ANWR, Mr. Chairman, makes sense for the following reasons:

(1) It would ensure secure domestic energy supplies for the United States for the coming decades and reduce dependence on imported oil;

(2) It would provide shipbuilding work which is badly needed for United States shipyards;

(3) It would provide seamen's jobs, thereby easing the manning problems highlighted during the Persian Gulf crisis;

(4) It would provide badly needed cargoes for U.S.-flag tankers as oil production declines on the Alaska North Slope;

(5) It would provide jobs and revenue for the State of Alaska;

(6) It would provide work for U.S.-flag carriers serving Alaska such as Sea-Land, Crowley and Tote; and,

(7) It would not cause harm to the wildlife, nor to the land. For example, the Central Arctic Caribou herd is four times larger now than when development began at Prudhoe Bay.

Presently, most of the crude oil tankers under the U.S.-flag are engaged in the transportation of ANS crude oil. This crude oil is produced from existing fields in Alaska's Prudhoe Bay area, and delivered via the Trans-Alaska Pipeline (TAPS), to Valdez, Alaska, where it is loaded onto tankers and transported to the lower 48 states. U.S.-flag vessels must be used in this trade in accordance with the Jones Act (46 App. U.S.C. 883) which reserves domestic waterborne commerce for U.S. documented vessels. There are currently approximately 48 U.S.-flag tankers in the "TAPS" trade.

On behalf of American tanker owners, we are proud of the service in transporting Alaska North Slope (ANS) crude oil to markets on the mainland. With the exception of the serious EXXON VALDEZ catastrophe, and the California spill shortly thereafter, maritime operations safely serve the energy consumption needs of the U.S. public, with a record of very few environmental accidents. We believe, under the new mandates of OPA '90, this record will be even more positive in terms of assessing the environmental impact of the carriage of ANS crude and the potential carriage of ANWR oil.

Set out below are some salient facts indicating the safety and environmental measures undertaken for transportation by U.S. tankers in the domestic trades.

- The Oil Pollution Act of 1990 enacted in the last Congress is presently being implemented. Already there is a state-of-the-art light installed at Bligh Reef, vessel traffic systems are imposed and numerous other preventive measures such as tug escorts are now in force. Oil spill prevention mechanisms, response activities, and compensation schemes are taking effect to the greatest extent possible.

- The Port and Tanker Safety Act of 1978 has been implemented, requiring segregated ballast tanks, crude oil washing systems and inert gas systems on all tankers over 20,000 DWT, as well as numerous other improvements.

- The reliability of shipboard equipment has been greatly improved in recent years with the advent of satellite-assisted navigation, improved radar, and redundant steering mechanisms.

- The implementation of MARPOL '78 insures that discharges at sea do not occur and that adequate waste reception facilities are provided.

- In three years (1981-1983), one of our largest operators lifted 45 million barrels of crude by tanker from Santa Barbara Channel spilling only one gallon.

- In the first seven years that the Trans-Alaska Pipeline System (TAPS) was opened, tankers moved over three billion barrels of crude oil out of Valdez. Approximately 200 barrels were spilled, which is equivalent to 67 barrels per billion barrels of oil shipped and a large portion of the amount spilled was recovered. This, of course, was pre-VALDEZ which unfortunately tends to negate the prior years of safe transit.

- Tankers have been transiting Santa Barbara Channel for well over 80 years. To our knowledge, no significant spills involving permanent environmental damage have occurred.

- One large oil company reports no spills since the inception (in the mid 1970's) of lightering operations in the U.S. Gulf from large (VLCC or ULCC) tankers to small tankers. Over 700 lighterings have occurred; these operations are far more difficult than loading from a single anchor leg mooring (SALM).

At present, there are approximately 10 million DWT of tankers active under the U.S. flag. About 70% of these tankers are employed in the distribution of ANS crude. These tankers form a vital part of the merchant marine which the U.S. can call upon in time of war or national emergency to carry petroleum products. Fortunately, the ANS crude market at this time is supporting these vessels and the manpower base necessary to run the ships.

However, as shown in the attached chart, when production in the Prudhoe Bay oil fields declines, vessels will be forced out of this trade with little prospect of finding cargoes elsewhere. The vessels would be laid up and, unless there is potential for production in ANWR, most will be scrapped, which will result in an exacerbation of an already acute shortage of militarily useful tankers.

We would add that lay up status does not guarantee that competent crews will be readily available as was proved when Operation Desert Shield necessitated the break out of vessels in response to the U.S. military emergency. Approximately 50% of the tanker manpower base is found on the vessels transporting ANS crude. A commercial market which utilizes ships is the only guarantee that ships and men will be available when needed for the national defense. It is essential that Congress enact legislation to authorize ANWR leasing as soon as possible because the product cannot come on stream until eight or ten years after leases are authorized. A continued use of the TAPS system by directing any oil found on the coastal plain into TAPS is a logical, environmentally sound method to proceed. TAPS and tankers have provided a safe method of transporting ANS crude and their use should be continued.

Other supporters of a decision to open the Arctic National Wildlife Refuge coastal plain to exploratory drilling and eventual development of oil fields will refer to the positive aspects of replacing the 25% of present domestic oil production represented by the Prudhoe Bay oil.

For example, employment will be boosted by 735,000 at peak level in 2005 with jobs spread throughout the country; the Nation's gross national product would be raised by more than $50 billion by the year 2005; and, the U.S. trade deficit would be slashed by nearly $30 billion in 2000 and by $68 billion in 2005.

To the considerable extent that the above factors add to the national security of the U.S., we add the very consequential benefits of keeping the major portion of the U.S. tanker fleet at work and available. This fleet operation provides major economic and national defense benefits for the United States.

In addition, supporters will show that oil can be produced on the Coastal Plain in an environmentally sound manner. I had the opportunity to visit the North Slope of Alaska and ANWR the summer of 1987. I was convinced, by observing the operations at Prudhoe Bay, that the technology available will ensure that no adverse effects to the ecology, environment, and wildlife will result from the development of ANWR.

With respect to this bill, we would like to make another brief comment. Simply stated, the positive impact that ANWR would provide for the U.S. maritime industry and our national energy security cannot be achieved unless the future oil production from ANWR is strictly reserved for domestic use. We see no reason to open ANWR solely for the benefit of foreign consumers. Therefore, we strongly support language in the bill to ensure that any crude oil eventually produced within ANWR be reserved for domestic use.

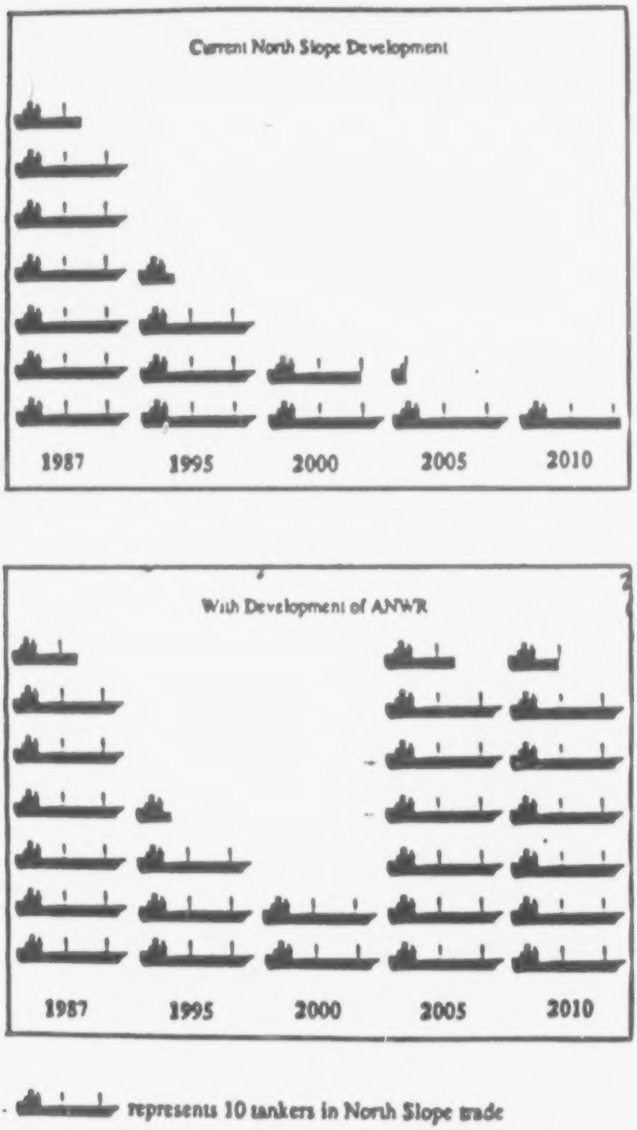
The alternative to the development of ANWR is really unacceptable because, among other things, it would result in the idling and subsequent destruction of the existing infrastructure (tankers, the Trans-Alaska Pipeline, etc.). This would be an unjustifiable waste in any circumstance, but especially in these days of emphasis on the conservation of resources as to the U.S. national security and U.S. productivity.

We appreciate this opportunity to comment for the record and strongly support opening the ANWR coastal plain to oil and gas development. It is noted that this area in question comprises only 1.5 million acres of the 19 million acre Arctic National Wildlife Refuge and that the "footprint" for development will be only about 13,000 acres.

ATTACHMENT

CRUDE OIL TANKERS IN NORTH SLOPE TRADE

All tankers in North Slope Trade are U.S.-Flag Ships



OFFICE OF THE PRESIDENT RVIA

Recreation Vehicle Industry Association
P.O. Box 2999 • 1896 Preston White Drive • Reston, VA 22090 • (703) 620-6003

STATEMENT
BY
DAVID J. HUMPHREYS, PRESIDENT
RECREATIONAL VEHICLE INDUSTRY ASSOCIATION
BEFORE THE
SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

March 12, 1991

My name is David J. Humphreys and I serve as President of the Recreation Vehicle Industry Association (RVIA). Thank you for the opportunity to comment today in support of Title IX of S.341, legislation which would permit oil and gas leasing of the Coastal Plain of the Arctic National Wildlife Refuge (ANWR).

RVIA is a national trade association representing over 600 manufacturers of recreation vehicles and their related suppliers who produce over 95% of this product sold in this country. The RV industry is essentially comprised of small manufacturers and is especially vulnerable to drastic swings in the supply of vehicle fuel. The oil embargo of 1973 had a devastating effect on the industry resulting in an 80% decline in sales and forcing many firms out of business. Analysis of the situation revealed that the drop in sales was caused not so much by the increase in gasoline prices as it was by consumer concern over its availability. As long as our country remains dependent on volatile and insecure foreign oil sources, the repetition of the "gas lines of 73" remains an ever present concern; and this concern is not solely limited to RV manufacturers. There are approximately 7 million owners of recreation vehicles in this country, all of whom are dependent upon a steady supply of fuel with which to operate their vehicles. Further, travel and tourism contributed $269 billion to the national economy in 1985 and was the direct or indirect support of almost 7 million jobs. The success of this industry is directly related to the availability of fuel oil.

At a time when our Nation's domestic oil production is continually declining and we are becoming more dependent on foreign sources of oil, it is more important than ever that the more promising prospects for major new oil discoveries be explored. The longer our country delays or actively curtails the orderly planning and implementation of exploration and production operations for domestic sources of oil, the more susceptible we become to the volatile conditions brought about by our increasing dependence on foreign supplies, as evidenced in the recent Persian Gulf war.

Moreover, ANWR lease sales would help reduce the current federal deficit by providing nearly $6.5 billion in new revenue from holding two 200,000 acre competitive bonus bid lease sales even if no oil is found and production royalties on ANWR oil could provide substantial additional revenue to reduce future federal deficits.

Several RV leaders ventured to Alaska to see the technology in place in Prudhoe Bay and to discuss the ANWR region with a variety of experts. They came away convinced that a leasing program in ANWR should be pursued. The oil companies have developed the expertise to ensure environmental impacts are minimized and the potential oil wealth of the area merits opening the Coastal Plain to further exploration.

RVIA is firmly convinced that opening the Coastal Plain of the Arctic National Wildlife Refuge to oil exploration and development is essential in light of the demonstrated requirements for fuel of the United States.

TESTIMONY OF MORRIS J. AMITAY SUBMITTED TO THE SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

Mr. Chairman:

My name is Morris J. Amitay. I am currently an attorney here in Washington, D.C., a Vice President of the Jewish Institute for National Security Affairs, and a former Executive Director of the American Israel Public Affairs Committee.

This testimony is submitted on behalf of an adhoc group of Jewish community leaders from around the country calling ourselves Americans for a Rational Energy Policy. We seek to educate the American public, the Jewish community and the Congress about the link between greater U.S. energy independence and freeing our foreign policies from the influence of oil. We have joined, with many other groups, the Coalition for American Energy Security, to urge the Congress to open the Coastal Plain of Alaska to exploration and development.

In the past we have taken positions in favor of the expeditious filling of our nation's Strategic Petroleum Reserve and the deregulation of natural gas. Today, the major issue we are concerned about is the future development of the potential of the Arctic Coastal Plain. This concern has been heightened by our nation's imports of oil overtaking domestic production.

The decisions that your Committee and Congress must take with regard to the future development of oil reserves in the

Coastal Plain area of the Arctic National Wildlife Refuge will undoubtedly have important ramifications not only for U.S. foreign policy in the Middle East, but also our nation's economic well-being. Americans who recognize the danger of growing U.S. dependence on foreign source oil, and particularly Middle East oil, should not hesitate in supporting legislation permitting orderly exploration and development in the relatively small Coastal Plain area with due regard for environmental safeguards.

We are faced with the undeniable fact that the current flow of 2 million barrels of oil per day from the adjacent Prudhoe Bay is now in decline. The Prudhoe Bay reservoir is more than half depleted already. During 1990, production declined by 100,000 barrels per day. It is projected that by the year 2000, production will be down 600,0090 barrels per day and will be nearly tapped out by the year 2014. Potential production from new finds in the Coastal Plain of ANWR is virtually the only domestic substitute and will, after authorization, take ten to twelve years to bring on stream.

While we also support increased conservation measures and greater attention and resources devoted to the development of alternative energy sources, the most urgent energy issue to come before the 102nd Congress will be whether development of the Coastal Plain of ANWR will be permitted.

The recent Gulf war was a telling reminder of how access to energy resources dictates foreign policies. And the gasoline lines of 1974 demonstrated how the oil weapon can be used as an instrument of coercion.

A report by the Anti-Defamation League of B'nai B'rith entitled "The Challenge Ahead: American Growing Dependence on Imported Arab Oil" specifically cited the need to open ANWR for oil development. It stated:

> "Another way to encourage production is to open the Arctic National Wildlife Refuge to oil exploration and production. The ANWR, close to the giant Prudhoe Bay oil field on Alaska's North Slope, is considered by both government and industry geologists to be the most promising untapped province in North America for the discovery of a supergiant oil field. The mean estimate is 3.2 billion barrels of oil, the maximum estimate 9.2 billion barrels."

The growing concern over this issue by the organized American Jewish community was also underscored by the Joint Program Plan giving guidance to 11 national and 113 community Jewish agencies. This document stated:

> "The ability of our government to formulate and conduct foreign policy undominated by energy considerations, and without fear of economic reprisals, must be a clear, conscious and fundamental objective."

If your Committee and the Congress act responsibly on ANWR by supporting Title IX of S.341 (the National Energy Security Act of 1991), in years to come we will be in a much better position to face up to attempts by foreign nations to play petro-politics with our oil needs.

We, therefore, wish to go on record in support of Title IX of Senate Bill 341 and hope that favorable Congressional action takes place in the future.

CONGRESSIONAL TESTIMONY OF TED AND FRANCOISE GIANOUTSOS, FOUNDERS OF THE NATIONAL FISH AND WILDLIFE FOUNDATION, ON THE ISSUE OF OPENING THE ARTIC NATIONAL WILDLIFE REFUGE (ANWR) TO OIL AND GAS DEVELOPMENT, SENATE BILL S.341, PRESENTED IN HEARINGS HELD ON MARCH 12, 1991.

The time has come to open the Artic National Wildlife Refuge (ANWR) to oil and gas development and as a consequence of this action, the time has come to seize the opportunity that this energy development presents to create two much needed national endowments - the National Endowment for Wildlife (NEW) and the National Endowment for the Environment (NEE).

The 1991 Persian Gulf war has dramatically brought all the issues surrounding fossil fuel - especially oil and gas - energy development and use into sharp focus. The war has done this even more vividly than the oil crisis of the early 70's, the creation of OPEC, major maritime oil spills, and the alarming "Greenhouse Effect" as a consequence of burning fossil fuels for energy.

Several major considerations have become obvious to all but the most obtuse observers. First, the U.S. economy and way of life, as is the case in all other industrial nations of the world, are dependent on fossil fuels with oil and gas being, by far, the fuels of choice. Second, America, even though one of the leading producers of oil and gas in the world and having some of the largest proven reserves of these fuels, nonetheless imports 1/2 of its consumption - more now than at the time of the energy crunch 20 years ago! Third, of some 900 billion barrels of proven reserves of petroleum worldwide, two-thirds are located in in the Persian Gulf/Middle East region. The current war only underscores the instability of this area and after the war, the region will hardly become, in the foreseeable future, one of the more stable places in this world.

Fourth, energy conservation is an oxymoron with respect to the American economy, lifestyle, and mindset. Energy conversion to cleaner fuels, not conservation is the answer to our problems, but this can only be accomplished over several decades in a non-disruptive manner if it is not to be counterproductive to the nation and its citizens.

The oil and gas field located under a very minor portion of the Arctic National Wildlife Refuge is considered to be a potential petroleum "elephant" - the term used by the oil industry to denote major petroleum reserves. If this were not the case, the debate to open ANWR would not have raged as long as it has. Finally, despite oil spills, either at the drilling site or in transit - especially by maritime transport - oil and gas development has not proved to be catastrophic to the environment as a whole, even though there have been many instances of localized degradations to the environment, all subject to varying and contradictory assessments.

Even with respect to global warming, the biggest environmental threat stemming from the use of fossil fuel, the jury is still out. AND, in any case, it is impossible to stop burning fossil fuels worldwide overnight. At best, it will take quite some time to do so.

Therefore, the time has come to address the oil and gas development of the ANWR in a responsible and rational manner. ANWR can and should be developed! One can impose even more regulatory restrictions on this development than on Prudhoe to insure minimal adverse environmental impact. It is incontestably in our national security interest to develop ANWR. The Gulf war has proven that beyond a shadow of a doubt. Who can say that it'snot better to drill ANWR than to kill America's sons and daughters to protect Persian Gulf Oil?

ANWR is in an environmentally sensitive area; it is a wildlife refuge but are the lives of caribous worth more than those of America's youth? As ardent wildlife conservationists, we think not! Indeed, we think that the supposed danger to wildlife that oil and gas development poses is greatly exagerated. The Prudhoe Bay experience, 70 miles to the West of ANWR has shown that despite twenty years of intensive oil and gas development the caribou herd as actually increased in size!

Because ANWR is a wildlife refuge and because the oil and gas field underlying a small corner of it is a potential petroleum "elephant" in size, a unique opportunity is at hand to do a great deal for wildlife and the environment for decades to come - indeed throughout the next century! That is why we are here today and this is what we have been working towards for more than five years now. We have testified on the ANWR issue before and have have refined our plan to create the National Endowment for Wildlife as a consequence of opening ANWR to new energy development.

Last year, we became aware of the effort by a group of America's most eminent scientists to create the National Institutes for the Environment (NIE). The rationale for the NIE is obvious when one considers the importance of environmental research and the need for unbiased studies and data. At the direction of Congress, the NAS is currently undertaking a feasibility study. One of the most important considerations is how the NIE would be financed as the proposal envisions a need of some 500 million dollars per year to fund the research and administration of the Institutes. With the current Federal budget deficits, it is hardly likely that Congress will appropriate anywhere near 500 million a year regardless of the desirability of the NIE.

We believe that the energy development of ANWR presents the opportunity to also create a National Endowment for the Environment and thereby fully fund the NIE. The two endowments go hand-in-hand because wildlife is obviously dependent on the environment and wildlife conservation is equally dependent on sound environmental research.

How appropriate it would be to have Governmental revenue from oil and gas development in a wildlife refuge form the basis for both the endowments for wildlife and the environment. After all, what are oil and gas but the fossilized remains of ancient plants and wildlife? And, are oil and gas not natural resources and thus an integral part of the environment of our world? No better use of a portion of the Governmental revenues of ANWR energy development could be found than to create the two much needed national endowments!

Specifically, our revised plan with respect to the Governmental revenue recommends the following the distribution of the entire pool of such revenues to be comprised of the totality of bonus bids, Alaskan royalties, Federal Government royalties, and a special ten percent per barrel fee (well-head price) on all oil and an equivalent fee on all gas extracted. The money would flow into this pool throughout the life of the energy development of ANWR. This pool of governmental revenues should be divided as follows:

1. Twenty percent to the State of Alaska to do with as it sees fit;
2. Twenty percent to the Federal Government to do with as it sees fit;
3. Twenty percent to fund the National Endowment for Wildlife (NEW);
4. Twenty percent to fund the National Endowment for the Environment (NEE);
5. Ten percent to provide for an oil spill clean-up and site reclamation fund;
6. Ten percent to provide for an alternative, clean, renewable energy conversion/conservation fund.

This division of the governmental proceeds of energy development at ANWR would not only provide a reasonable share to the State of Alaska and to the Federal Government to be used in a variety of areas where they both best see fit but also for the first time, a major portion (40 percent) of the revenue coming from a wildlife refuge located in an environmentally sensitive area would be used for nationally desirable endowments which would benefit all Americans for generations to come.

The capital of these endowments and funds should be invested solely in U.S. Government Treasury securities. The majority (two-thirds to three-quarters)should be invested in long-term interest-bearing U.S. Treasury securities to provide annual cash flow for projects and the minority (one-quarter to one-third) should be invested in long-term zero-coupon U.S. Treasury securities to provide for the growth of the funds/endowments.

The oil spill clean-up/reclamation fund could have a fifty-fifty split between interest-bearing and zero-coupon securities. In addition to providing for the growth of the funds, the zero-coupon portion would assure the availability of the money to reclame the site once all energy extraction is completed, i.e. to literally haul-out everything that was hauled into the refuge to extract the energy and to return the site to as-near its natural condition as possible. This fund would be jointly administered by the State of Alaska and the Federal Government.

Clean-energy conversion/conservation fund would be administered by the Department of Energy and would be used to stimulate conversion to cleaner fuels and to reward conservation efforts by individuals, groups, businesses and governmental entities. Any unused monies in this fund or in the preceeding oil spill/reclamation fund would be equally divided between the State of Alaska and the Federal Government at the end of the energy extraction project at ANWR.

The National Endowment for Wildlife should be located in the most obvious place - the National Fish and Wildlife Foundation. Not only does the Foundation have the broadest possible mandate for the conservation and protection of fish, wildlife, and plants of any entity in the United States but in addition, it also has worldwide authority granted to it by Congress. Most importantly, the Foundation has as part of its original charter the ability to solicit and accept participation of of individuals, businesses, and organizations in its programs. This provision is exceedingly important as it provides the mechanism by which these entities can participate and become involved directly in the NEW. They may establish restricted endowment accounts (REAs), another of our ideas which we developed and put into practice in 1983 when we founded the National Fish and Wildlife Foundation. These REAs, not only would increase substantially the capital of the endowments but would consequently insure its integrity. No other existing or proposed fund receiving revenues from energy development at ANWR envisioned by various legislative approaches offers the flexibility and benefits of the NEW located in the Foundation where it belongs. Finally, because of the authority granted the Foundation by Congress in its charter, the endowment and the Foundation would be able to directly interact in a programmatic fashion with all other governmental entities (local, state, Federal, and international), all organizations (environmental, wildlife conservation, public, or private), businesses, and individuals, to implement wildlife conservation projects, not only in the United States but throughout the world.

The National Endowment for the Environment should be located where it obviously belongs, the proposed new National Institutes for the Environment to be created by Congress. It would be exceedingly beneficial if Congress would provide when Congress creates the NIE the same type of broad authority for individual /business /or organizational participation that it did in the case of the NFWF. This would result in similar benefits as stated above, specifically a substantially larger capital in the endowment and the assurance of the integrity of the endowment through citizen participation.

The one hundred percent U.S. Treasury securities investment strategy in the above endowments and funds has many benefits. The cost of acquiring the securities is low or altogether non-existent when the securities are purchased directly from the U.S. Treasury or the Federal Reserve banks. The capital is safe and secure. And, more importantly, every security purchased and held in this manner is one less security available to foreigners who already own too much of our national debt (nearly one-third) which was so conveniently and short-sightedly exported during the '80s. Indeed, this investment strategy works equally well for REAs and for funds/endowments established for entirely different purposes than wildlife conservation/environment. It works for education, arts and humanities, historical preservation, etc.. We even came up with a name for it several years ago. We called it the N.E.A.T. concept which stands for National-debt based Endowments for America's Treasures. If applied on a massive scale, these N.E.A.T. endowments/funds/REAS could literally soak up the one-third of our national debt now in foreign hands. These foreigners pay no taxes on the interest earned on the U.S. Treasury securities they hold. If thoses securities were held instead in 501(c)(3) N.E.A.T. funds, no taxes would be paid either BUT the difference is that the interest would go towards safeguarding America's treasures for the benefit of all Americans rather than providing income to foreigners to be used to purchase even more of our national debt and thereby increase their stranglehold on our economy or to purchase American property and/or businesses. It is therefore in the national interest to utilize this investment strategy for the NEW and the NEE and to recommend this strategy to all those individuals, organizations, and businesses wishing to establish REAs in these two national endowments.

The creation of these multi-billion dollar endowments is certainly in the national interest. It is also evident that we should produce as much as possible of the petroleum which we consume, even if it lies beneath a wildlife refuge. It goes without saying that it has become in our national interest to convert as rapidly as possible to cleaner sources of energy. But while we do that, we need to become less dependent on foreign sources of oil and one way to do that is to produce more of our own, especially when in doing so we can impose far stricter environmental controls on domestic production than are imposed by others on foreign production.

Let's open ANWR to oil and gas development. Let's do it with all the environmental controls necessary to minimize any adverse environmental impact to the Refuge. And let's take advantage to this once in a lifetime opportunity that a petroleum "elephant" lying beneath a wildlife refuge presents to create the NEW and the NEE which will insure major funding for wildlife conservation projects and environmental research throughout the twenty-first century.

JENNIFER LYN WASSERMAN
510 East 86th Street
New York, NY 10028

April 1, 1991

Hon. J. Bennett Johnston
United States Senator
SD-364 Dirksen Senate Office Bldg.
Washington, DC 20510-6150

Artic National Wildlife Refuge

Dear Senator Johnston:

I am a seventeen year old student in the 11th grade of The Dalton School in New York City. I spent last summer travelling through and studying about the Artic National Wildlife Refuge ("ANWR") and I have a personal knowledge of the impact which increased oil exploration would have in this area.

I would like to testify before the Senate reaches any final decision about drilling in the Refuge.

Before entering ANWR, I spent ten days at Prudoe Bay and Kaktovik, an Inupiat village of 175 eskimos within ANWR's boundaries. While in Prudoe Bay and Kaktovik, I spoke with drilling advocates, environmentalists and the residents of ANWR. I believe that I can fairly summarize the pros and cons of each viewpoint. I enclose a copy of the paper which I wrote after returning to the University of Alaska at Fairbanks.

Respectfully,

Jennifer Wasserman

Jennifer Lyn Wasserman

Enclosure(s)

Oil vs. Wilderness
in
Alaska

J. Wasserman
ALR - 195 - 301
March 1991

J. Wasserman
ALA-195-301

"Something will have gone out of us as a people if we ever let the remaining wilderness be destroyed... We simply need that wild country available to us, even if we never do more than drive to its edge and look in."(Outward Bound, 46). This quote by Wallace Stegner best describes the feelings of those who long to protect America's unadulterated lands. It was the vastness of land which created the backbone of America's strength and culture. America still has vast lands. However, it is not certain that America will protect these lands which are currently threatened with destruction.

Alaska's Arctic National Wildlife Refuge (ANWR) is a vast area. Within this 19 million acre refuge are 1.5 million acres of coastal plain, which represents eight percent of ANWR. These 1.5 million acres have been at the heart of controversy for some ten years. This land has set environmentalists and oil advocates on opposite sides of the fence.

Dubbed "1002" by The Alaska National Interest Lands Conservation Act (ANILCA), the area is known to contain promising amounts of oil. It is not known whether this oil is economically viable or even entirely recoverable, but there is continued speculation of a 19 percent chance of major oil - a high percentage by oil standards. "Guesstimates" range from a conservative .5 billion barrels upwards to 9.5 billion barrels (a barrel equals 44 gallons). 3.2 billion barrels is the favored assumption. The questions are whether this quantity is truly necessary and what is at stake if drilling were to occur?

Because this is such a deep rooted argument, it is clear this is not a simple issue. From the point of view of the environmentalists,the coastal plain of ANWR is an area of unique arctic botany and large wildlife populations. Once a year ANWR is the location of mass caribou calving whose survival, in turn, effects the lives of two native communities. Environmentalists want to see 1002 protected from development along with the other 92 percent of the refuge. They also argue that much of the culture of the United States revolves around the frontier mentality and the land from which this mentality stems. "Disregard for America's land...is a demonstrable disregard for ourselves" (LaPage, Raney,10). From gold to coal to oil, Americans have successfully "disregarded" themselves for years

The advocates for oil exploration and drilling, on the other hand, offer the argument that America is still rich in untarnished lands and if we continue to set aside and protect land rich in resources, the country will suffer economic repercussions.

Alaska is the epitome of the two extremes. Alaska is cherished for the open country it offers. But it is also crucial for the resources which the land offers. The largest of the states, one - fifth the size of the lower 48, Alaska still remains the "Last Frontier." From a possible 80,237,264 acres, 56,486,598 are protected lands (Kofinas, 7/90). These areas are not wasted; they are utilized by recreationalists, wildlife and natives, many of whom still live in accordance with the old ways. Prior to protection from the government, these lands were open to hunters, trappers, whalers and miners and, from the gold rush of 1886 on, Alaska's natural resources have been greatly taxed.

The 1968 discovery of oil in Prudhoe Bay was the most recent of the mass production of the state's natural resources. Beginning in 1977, the Prudhoe Bay fields and later the neighboring Kaparuk fields, began a ten - year producing program which had a peak production of two million barrels a day. Prudhoe and Kaparuk are the largest oil fields of their kind in North America and are responsible for 25 percent of all oil produced in the United States (British Petroleum, 7). Now, with production at the fields steadily declining ten percent annually, oil companies have set their sights on 1002. Unfortunately for the oil industry, 1002 has been claimed already for what it offers without development - much open space, excessive botany and occasional relief from the mosquitoes - by the thousands of animals who exist on this land. It is for the future welfare of these animals that conservationalists feel it is crucial to protect the refuge.

Unaware that the coastal plain to which they migrate yearly is at the center of controversy, the 180,000 members of the Porcupine caribou herd adopt 1002 as their calving grounds. The herd's arrival at the plain is one of the only constants in Porcupine Caribou life (Blazer, 7/90).

Consequently, drilling in the plain would have nothing but negative effects upon the animals as they would be forced to relocate. True, the caribou residing on the North Slope near Prudhoe Bay have adapted to the massive development, but these animals have lower body weight, are more sedentary and frequently produce unhealthy offspring (Whitten, 7/90).

Although the caribou are the most notable users of the area, muskoxen too play a key part in the character of the coastal plain. The entire North Slope's population was killed off during the latter part of the nineteenth century and it was not until the late twentieth century that they were carefully reintroduced to the area. Today they are permanent members of the coastal plain and, like the caribou, are sought by both game and subsistence hunters. Both groups of hunters are given stringent permits which allow for only a small number of the animals to be taken. Yet, because the hunting of these animals is permitted, even if in moderation, there are less than 500 muskoxen in this traditional environment. Like the caribou, muskoxen would not adapt well, if at all, to a developed area. The United States Fish and Wildlife Service has concluded that "major negative effects on the 1002 area muskox could occur from oil development." Although their population in the area is very small, they are necessary to the ecosystem and food chain to which they belong.

Disruptance of any sort from the presence of an oil field would disrupt the food chain and its trophic levels - from the perennial lichen at the bottom to the predatory wolves and bears near the top and, of course, the caribou and muskoxen in between. At the top of this unique food chain are the natives who utilize the 1002 area (Bader, 7/90).

There are two native groups living within the ANWR boundaries - the only permanent human presence in the refuge. The Gwich'in Indians of Arctic Village reside in the Southern Brooks range, while the Inupiat (Eskimos) of Kaktovik live on Barter Island - 65 miles to the east of Prudhoe Bay. Although neither use 1002 directly, both communities rely heavily upon the Porcupine Caribou for clothing and food.

By the codes of Alaskan wilderness designation (which differ from those in the lower 48), subsistence hunting is a prioritized activity. This is crucial to native populations who's culture is based upon the land alone. The Gwich'in Indians are staunchly against the development of the coastal plain and they do not benefit at all from the oil industry or its money. Even if the Gwich'in peoples were to "cash in" on oil revenue, too much of their traditional lifestyle is at stake for them to favor pro-development.

However, the village of Kaktovik is located on the North Slope of the Brooks Range, as is Prudhoe Bay. This village receives large amounts of revenue because of taxes on Prudhoe and thus the village's residents are split in their opinion over the future of 1002. Some tend to favor the material benefits of the oil companies, while others favor the customary lifestyle. It was with this money that the people of Kaktovik were able to receive running water, a health center and build a four million dollar school for 25 students. If the drilling were to occur, Kaktovik would receive twice as much money from oil than they do today since it would still be getting money from Prudhoe as well as from 1002. At present, oil money has also cast a darkness over the village - one of alcohol abuse and the mistreatment of natives by oil companies and thus the villagers are wary of the industry of having it in their backyard as would be the case if 1002 was developed. An Inupiat man, who worked on the development of Endicott, British Petroleum's newest facility, stated that he worked longer than standard hours and was not given the period of rest other workers were given. An Inupiat woman has said that she feels threatened by western ideals and believes that Inupiat ways were slipping because her people had become so materialistic . Designating the area wilderness would potentially alleviate this split among the community for they would still receive revenue from the Prudhoe fields, which alone is a great amount in comparison with their lifestyle and, as one Inupiat states, "jobs won't always be here...but you can always go out and hunt." (Lemonick, 99). Although subsistence also has priority in lands designated for recreation, hopefully nominating 1002 for wilderness will ensure that the land remains as pristine as possible.

To avoid scarring the landscape, wilderness designation calls for commercial activity limited to guides with backpackers, All Terrain Vehicles and snowmobiles allowed only for subsistence purposes and only when the permafrost is frozen. Air traffic is permissible as are a limited amount of landing strips which have not been man made. These are the terms offered by the Department of Interior. However, the rules for hunting should be more stringent and recreational hunting should be eliminated for the following reasons. Alaska is the only state in which game hunting is permitted in land protected as wilderness where the hunters may not employee the use of mountain bikes, motorized vehicles, permanent structures, etc. Many of the animals in 1002 are in a fragile state and thus should be closely managed. The caribou who have come to 1002 are, in large part, cows who have come to give birth. The calves should be given the opportunity to survive the harsh arctic environment(many already succumb the first year to weather and predators). If hunting solely for sport were allowed, the young caribou may be depopulated. Likewise, the muskoxen, moose and bears of the area, all relatively low in quantity, should be allowed the chance to increase in numbers to ensure the species survival on the coastal plain. The hunting of bears and muskoxen are even limited to those hunting for subsistence purposes. If these animals are off limits to hunters because of a sheer lack of numbers, it is obvious that they would not react well to mass development which puts an entirely different pressure upon the animals. Hunting solely changes population size whereas mass development impacts the animals movement and displaces habitat.

There too are other mammals, birds and fish who all have a far greater chance of survival in a land touched only by the forces of nature rather than forced adaptation to pipelines, trucks and man.

Obviously there are drawbacks to not developing 1002. Fortunately, there are options to reconcile this loss. Presently, it is not conceivable that the government would delve into alternative means of energy since it is cheaper to obtain energy from known resources instead of committing to the research of new forms. It is for this reason that alternative energy and conservation will become crucial in the years to come.

Currently, the United States consumes 62 percent imported and 38 percent domestic oil. It is unfair that the oil industry has often portrayed 1002 as the sole hope regarding the future of domestic oil when, in reality, ANWR has one of the lower estimates of recoverable barrels available then the estimates of other potential fields. Strangely, the oil companies have been shying away from known potential fields in and around Prudhoe Bay such as Mt. McIntyre, West Sak and Seal Island. In fairness, these sites contain oil which is not embedded as deeply in the ground (4 - 5,000 feet as opposed to the standard 8 - 9,000 feet) and thus would be costlier to produce (Dotson, 7/90). Development, however, of a field near Prudhoe Bay would be less than or equal to the cost of developing a place as remote and inaccessible as 1002. Also, there are resources outside of Alaska. Chevron has a giant offshore structure on the coast of Santa Barbara, California, ready to be pumped as soon as it receives its permits.

In light of the dilemma of choosing an oil site and allowing the estimated ten to 20 years for production to begin, one must wonder whether Americans will accept the idea of conservation. Conservation need not take years of education to introduce into daily life, nor must it be so drastic that the oil companies must be impaired by substantial loss of business. Americans are too spoiled to be expected to alter their lifestyles drastically or even consciously. Transportation is responsible for two - thirds of the fuel consumed in America and should thus be the focus of conservation efforts (Kerasote, 19). An increase in rapid transit and an increase in oil emission standards should both be attainable objectives. If the standards for car emission are raised only 1.5 to two miles more per gallon, in only a few months we could save some three billion barrels of oil - the proposed estimate for ANWR. It is wrong for environmentalists to call for cars which can run anywhere from 40 - 60 miles per gallon for the oil industry is one of the biggest in the nation as well as the biggest in Alaska and it would be illogical to lessen it so extensively.

Oil is crucial to the Alaskan economy, none the less, the decision not to drill ANWR would not create a crisis. Eighty - five percent of the state's total income comes from land taxes on Prudhoe Bay. (Lemonick, 97). The state can still rely on Prudhoe Bay possibly until the year 2030 (Dotson, 7/90). In the meantime, the state can lease the fields around Prudhoe to the companies, so that when the Bay dries up or is no longer economically feasible, there will be fields ready to be tapped. The state could also channel more energy into increasing tourism - Alaska's fourth largest industry (Bader, 7/90).

Because guiding backpackers is the only commercial activity allowed in a wilderness area, it is possible for Alaska to design a system that requires all groups of a certain size and those who came for specific purposes such as fishing and bird watching, to hire a state appointed guide prior to entering the "backckountry". Even if there is a push for more visitors to come to ANWR, it is not likely that the refuge will be trampled as national parks often are for it is so remote that travel is both inconvenient and costly.

Those who do make it up however, are lucky. They are lucky to have experienced the looming Brooks Range, the curiously mellow caribou, the occasional lone wolf and the seemingly endless windswept coastal plain. The coastal plain that is 1002 is perhaps not as estethically pleasing as miles of glaciers, but those who look closely see that the plain has life and character all its own. The plain is cut with winding rivers that empty into the shores of the Beaufort Sea. There is countless animal life.

It is unfortunate that a brief position paper can present only a few points. There are factors which were not mentioned but those that are included are strong enough to convince the state drilling ANWR is not necessary in the near future and that Alaska's economy and her natives are not going to suffer if the land is not developed. Wilderness is crucial to the American spirit. It is crucial to the climber, to the fisherman, to the native who has based his life around the land and to the armchair traveler who just wants to know its there.

APPENDIXES TO MARCH 14, 1991 HEARING

(Title XV)

Appendix I—Responses to Additional Questions

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

OFFICE OF
THE COMMISSIONER

April 12, 1991

Senator J. Bennett Johnston, Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510-6150

Dear Chairman Johnston:

I am pleased to forward to you the Commission's responses to the written questions of you and other members of your committee concerning reform of the Public Utility Holding Company Act of 1935. I apologize for the delay; however, because of the significance of your questions, it was necessary that all Commissioners review the proposed responses. If I can be of further assistance, please do not hesitate to contact me.

Sincerely,

Edward H. Fleischman
Commissioner

Enclosure

Questions from Senator Johnston

1. **During the hearing you indicated that it may be appropriate for the SEC to adopt a more flexible standard concerning consolidated debt ratios for registered holding companies in situations where such ratios would be affected by investment in EWGs which are non-recourse to the parent holding company or other subsidiaries. Please provide statutory language that would address this matter.**

Answer:

Section 7(d) of the 1935 Act reflects Congress' concern that each of the several entities comprising a traditional electric utility holding company has a simple capital structure and incurs only those amounts of debt that can be adequately serviced by the operations of the utility. In this regard, the Commission has generally required that a registered holding company system and its public-utility subsidiary companies maintain a 65%/30% debt/common equity ratio; the balance of the capital structure, 5%, is frequently preferred stock.

Traditional financial standards, however, will not necessarily apply to EWGs, which are expected to be project-financed entities generally characterized by large amounts of nonrecourse debt. Financing via nonrecourse debt is intended to limit the exposure on the debt solely to those assets of the EWG that have been subjected to a security interest in favor of sophisticated project-finance lenders. Nevertheless, registered public-utility holding companies investing in EWGs may also desire to participate in the financing of EWGs by purchase of equity or debt securities or by guarantee of debt securities of EWGs. The following language, if adopted to amend S. 341, would allow the Commission to implement a more flexible standard concerning consolidated debt/equity ratios as they relate to registered holding company investments in EWGs:

> Section 15001(e) of S. 341 is hereby amended by inserting the following provisions:
>
> (3) In determining whether to approve the issue or sale of a security by a registered holding company for purposes of financing the acquisition of an exempt wholesale electric generator, or the guarantee of securities of an exempt wholesale generator by a registered holding company, the Commission shall find that such security is not reasonably adapted to the earning power of such company or to the security structure of such company and other companies in the same holding company system, or that the circumstances are

such as to constitute the making of such guarantee an improper risk for such company, only if the Commission first determines that the issue or sale, or the guarantee would have a substantial adverse impact on the financial integrity of the registered holding company system.

(4) In determining whether to approve the issue or sale of securities other than with respect to its exempt wholesale generators, or any other transaction by a registered holding company and its subsidiary companies not within the scope of this section, the Commission shall not consider the effect of the exempt wholesale generators' capitalization and earnings on the registered holding company system unless the effect would be to have a substantial adverse impact on the financial integrity of the registered holding company system.

The Commission requests that the Committee, in its report to the Senate, indicate that the intent of the foregoing amendment is to provide the Commission sufficient discretion to accommodate the developing wholesale generator industry while protecting the basic financial integrity of the several registered holding company systems. To that end, the Committee's report should indicate that the Commission, in evaluating EWG-related financing proposals by registered holding companies, can look to a variety of factors relating to the financial condition and results of operations of the entities comprising the holding company system, including, but not limited to, consolidated debt/equity levels, cash flow analyses, contractual provisions of the securities issued or guaranteed, and debt and preferred stock ratings of the holding company as well as the subsidiary companies in the registered holding company system.

For example, the Commission would be intended to be more flexible in its analysis of the effect of investment in, or guarantees of the securities of, a leveraged EWG by a registered holding company that itself is in sound financial condition than it would be with respect to investment in or guarantees of the securities of an EWG by a registered holding company whose subsidiary operating companies are experiencing cash flow problems that would be exacerbated by diversion of holding company resources and management in the event that the EWG fails to secure long-term power supply contracts or such contracts prove to be uneconomical.

2. During the hearing you indicated that you would be willing to provide the Committee with statutory language that ensures that registered holding companies are able to obtain expeditious approval for the issuance of securities for purposes of financing EWGs. Please provide statutory language that accomplishes this purpose?

Answer:

Financing applications by registered holding companies are generally not challenged except insofar as they relate to acquisitions under sections 9 and 10 of the 1935 Act. Inasmuch as S. 341 expressly authorizes registered holding companies to acquire interests in EWGs without seeking Commission approval under those sections, the Commission review of EWG-related financing contemplated by S. 341 should impose no undue delay on the registered holding companies.

In connection with holding and subsidiary companies' financings generally, the staff of the Commission has in place a procedure, referred to as "budget financing authority," whereby a registered holding company or its subsidiary can seek financing authority from the Commission for an 18-24 month prospective period. Upon approval, the company can access the market with individual security issues as the company deems appropriate during this period. It would appear that in planning the construction and operation of an EWG, as for any other construction project, the holding company would be able to approximate the time of its financing needs to take advantage of the staff's budget financing authority, and thereby mitigate any potential delays in securing authorization for an investment in the EWG.

Question of Senator Malcolm Wallop

What is the application of PUHCA to power plants owned by U.S. companies outside of the United States?

Answer:

The definition of "electric utility company" under PUHCA generally extends to any company which owns or operates facilities, wheresoever located, used for the generation, transmission or distribution of electric energy for sale. Thus, a company owning a power plant outside of the United States would be an electric utility company under PUHCA, and the U.S. company owning that foreign utility would be a holding company required to register under section 5 of PUHCA unless it could come under an exemption specified in section 3 of PUHCA.

A registered U.S. holding company would be prevented by PUHCA from owning a foreign power plant. Section 11(b)(1) restricts that company to a single, integrated public utility system which, by the terms of the statute, is geographically limited to an area or region of the United States. Although Congress did provide for the retention in certain circumstances of additional public utility systems that were located in a contiguous foreign country, PUHCA does not provide for the acquisition of foreign utility companies by a registered holding company.

If the U.S. company is exempt from registration under PUHCA, the provisions of section 11 do not apply expressly. The foreign utility interest must be consistent with the terms of the holding company's exemption and, further, not be detrimental to the public interest and the interest of investors and consumers (the "protected interests"). The availability and/or continued enjoyment of an exemption depends on specific facts and circumstances.

Section 3(a)(5) of PUHCA does except from registration holding companies with no material domestic public utility interests. These companies may freely acquire foreign utility companies. 1/ There are possible statutory constructions which have not, to date, been reviewed or endorsed by the Commission that may allow such companies to acquire foreign utility subsidiaries without losing their exemptions.

1/ See INDECK Energy Servs., Inc., Holding Co. Act Release No. 25237 (Jan. 4, 1991).

A stand-alone utility (one without a holding company) could acquire a foreign utility company that, having no domestic utility business and no material income from domestic sources, received an unqualified order of exemption under section 3(b) of PUHCA. 2/

2/ See Washington Water Power Co., Holding Co. Act Release No. 25236 (Jan. 2, 1991).

Question of Senator Nickles

We understand that IPPs will rely heavily upon so-called "project financing" through which a bank, securities house, insurance company or other source of capital will only extend financing depending upon the IPPs obtaining of an iron-clad long term "take-or-pay" contract for its power from a utility. The Wall Street rating agencies have indicated that such "take-or-pay" contracts will likely be viewed as debt on the books of the utility purchasing the IPP's power, thus lowering that utility's credit rating and increasing the utility's cost of credit which it passes on its customers in its rates.

What is project-financing of IPPs all about?

- Why do IPPs need to [do] this project-financing? Are IPPs too risky for present companies to risk their own assets? If so what does that tell us about the wisdom of promoting IPPs at the expense of utilities?
- Is it fair to permit a state PUC to force a utility to accept IPP power if it must enter into such a long term contract to do so at the expense of its own credit rating?
- Why aren't long term "take-or-pay" contracts for IPP power rife with the same prospects for the problems that beset the natural gas industry in the 1970s when expected gas demand never materialized and utilities were stuck with high gas purchase requirements they could not use?

Answer:

There is a general consensus that the financial markets will require IPPs to be project financed. That is, debt lenders will provide capital only if it is secured by a corporate entity which controls project assets and revenues. Equity participants, in turn, will demand that the debt be non-recourse (i.e. limited to recourse against the project assets, except where the equity participants or others have agreed to furnish a guarantee). The most effective way to meet these requirements is by creating a separate corporate entity to develop an individual project. Further, for reasons of organizational convenience, risk separation and cost accounting, corporations generally will require the creation of separate subsidiaries to own and operate IPPs.

With respect to the wisdom of state PUCs imposing requirements on utilities subject to their jurisdiction to accept IPP power and the comparison of IPP contracts with the "take or pay" contracts associated with the natural gas industry in the 1970s, these matters are best answered by the Federal Energy Regulatory Commission, the individual states and the National Association of Regulatory Utility Commissioners.

Questions of Senator Akaka

Commissioner F[l]eischman, Section 15001(a)(2) of S. 341 defines an "eligible facility" to be "a facility, wheresoever located, used for the generation of electric energy . . ." (Emphasis added.) Title IV of S. 570 contains an essentially similar provision.

1. Does the scope of the phrase "wheresoever located" and the corresponding term in Title IV of S. 570 extend to both foreign and domestic facilities?

Answer:

I would presume so, because the underscored phrase above is not limited geographically.

2. Commissioner F[l]eischman, assuming the enactment of PUHCA reform legislation contained in S. 341 or S. 570, what further requirements, if any, would have to [be] satisfied in order for a holding company to own and operate an electric generation facility in a foreign country?

Answer:

Both bills would provide for the acquisition and retention of an EWG in a foreign country without Commission approval. 3/ However, to the extent that a registered holding company acquires a foreign EWG, any related financing by the registered holding company would remain subject to Commission approval under the 1935 Act, as would the holding company's guarantees of EWG securities and the entering into service, sales or construction contracts or the creation or maintenance of any other relationship (other than the acquiring and holding of securities or other interests in an EWG) between the EWG and the registered company or its affiliates and associate companies.

In addition, S. 570, in effect, would require an exempt holding company owning a foreign EWG to have appropriate

---

3/ The acquisition of any distribution facilities, or any transmission facilities other than those necessary to interconnect the EWG to transmission facilities necessary to effect its wholesale sales, would remain subject to the 1935 Act. See section 2(a)(3) of the 1935 Act ("electric utility company" includes "any company which owns or operates facilities used for the . . . transmission, or distribution of electric energy for sale . . . .").

means in place to determine the allocation of costs between the EWG and any associate, affiliate or subsidiary company that provides electric service at retail.

Finally, S. 570 effectively would require both exempt and registered holding companies that own foreign EWGs that contract to sell electricity to an associate, affiliate or subsidiary company providing electric service at retail to have received prior approval of the contract from each affected state commission.

Of course, if a foreign EWG sold power only to unrelated third parties, these provisions of S. 570 would not apply.

Department of Energy
Washington, DC 20585
April 17, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

On March 14, 1991, Linda G. Stuntz, Deputy Under Secretary, Office of Policy, Planning, and Analysis, testified before your committee on Title XV of S. 341, Public Utility Holding Company Act Reform (PUCHA).

Following the hearing, you submitted written questions on behalf of yourself and Senators Bumpers, Wallop, Nickles and Akaka to supplement the record. Enclosed are the answers to those questions.

If we can be of further assistance to you or your staff, please contact our Congressional Hearing Coordinator, Barbara Barnes, on (202) 586-6341.

Sincerely,

Jacqueline Knox Brown
Assistant Secretary
Congressional and Intergovernmental
Affairs

Enclosures

QUESTION FROM SENATOR JOHNSTON

Question: Committee staff has prepared a memorandum (enclosed) on the subject of debt leveraging by non-utility generators (NUGs). It generally concludes that such leveraging is not financially imprudent and does not give NUGs a consistent cost of capital advantage as compared to utilities. Do you agree with these and the other conclusions of this memorandum? Please provide any analysis you may have on this subject.

Answer: We have reviewed the memorandum ("Financial Issues in PUHCA Reform") by William Conway and Karl Hausker, dated March 13, 1991. We agree with its principal conclusions, as listed on p. 2 of the memorandum.

In response to your request for DOE analysis on this subject, a brief discussion of the leveraging issue is attached which was prepared by DOE as an insert to the record of your hearing of March 14. This insert was requested by Senator Wirth.

Insert on Leveraging
(Requested by Senator Wirth, transcript p. 78)

FINANCIAL LEVERAGING AND THE COST OF CAPITAL FOR INDEPENDENT POWER PRODUCERS

There is some concern that independent power producers (IPPs) may enjoy an advantage over regulated electric utilities based on the way IPPs finance new generating facilities. This concern centers around the fact that utilities are frequently proscribed by regulation from using high levels of debt to finance new capacity, while IPPs are not directly constrained by regulation as to how they may finance new generating plants. IPPs can, and do, finance new plants using a debt-to-equity ratio as high as 90/10 (that is, 90 percent debt and 10 percent equity). Because some believe that debt financing is generally cheaper than equity financing, there is concern that IPPs may have a consistently lower cost of capital than utilities, and that, as a result, competition between IPPs and utilities may be tilted unfairly in favor of IPPs.

The Effects of Capital Structure and Risk on the Cost of Capital

Economists have developed two ways of thinking about the impacts of financing ratios and risk upon a company's overall cost of capital. These are the "capital structure" approach and the "total risk" approach. The two approaches are not mutually exclusive; rather, they have somewhat different emphases.

The Capital Structure Approach. In this view, a particular company may be able to reduce its total cost of capital by substituting debt financing for equity financing. Debt financing has a lower cost than equity financing for three reasons. First, debt holders have the first claim on company income; they are paid from company revenues before equity holders are paid. Thus, debt holders bear less risk and require a commensurately smaller return to offset that risk and make investment attractive. Second, debt holders receive a fixed rate of return on their investments, whereas the return on equity fluctuates with the company's profitability. Again, this reduces risk for debt investors. Third, debt payments are tax deductible to the company, whereas dividend payments to equity holders are not.

Notwithstanding these three reasons why debt financing can be cheaper than equity financing, a company's total cost of capital may be reduced only up to a point. As debt is substituted for equity, the company's stocks and bonds are perceived by investors as becoming riskier. This is because debt payment is a fixed obligation of the company and must be paid regardless of the company's income. If the company's sales and revenues are subject to fluctuations due to economic conditions or weather conditions, there is a risk that it may not have sufficient income to make its debt payments. The equity component may be too small to absorb the loss and the company could become insolvent. Thus, as debt becomes a larger and larger proportion of total capital, the cost of debt--that is, the return required to attract investment in a company's debt--increases. After some threshold is reached, greater proportions of debt financing will raise, rather than lower, a company's total cost of capital.

This analysis implies that an IPP with a highly leveraged capital structure--i.e., a high percentage of debt financing--and a low overall cost of capital is able to achieve this combination only because its level of debt is not perceived by the financial community as particularly risky, given the IPP's business situation. Otherwise, investors would not provide such a high level of debt financing, but would require the company to use a greater level of equity financing.

The Total Risk Approach. In this view, the financial community evaluates the total business risk associated with a particular company and determines the appropriate compensating return on that company's assets. How these assets are financed--with debt or equity--is irrelevant. The total return will be divided between debt and equity components, but the overall return on investment will not be affected. This view holds that, at least below the threshold where the fixed obligations (debt) of a company become oppressive, the relative proportion of debt and equity financing does not affect the company's cost of capital.

(Note: The analysis prepared by staff of the Senate Committee on Energy and Natural Resources found empirical support for this view when it found no consistent cost of capital advantage for IPPs over utilities despite a wide variation in debt/equity ratios.)

What is important is whether the company is judged by the financial community as being more or less risky as an investment vehicle. In short, if a highly leveraged IPP has a low cost of capital, it is because it has a low overall risk, and not because it is financed largely with debt.

Thus the two approaches lead to essentially the same result. The financial community's perception of how risky a company is has a far greater effect on the company's cost of capital than does the company's capital structure. In cases where an IPP has a low cost of capital, it reflects the level of risk associated with the company's activities far more than it does the IPP's capital structure.

Distribution of Risk Among a Utility, an IPP, and Others

The distribution of risk between an IPP, its business partners (such as equipment vendors and fuel suppliers), and a purchasing utility--and the resulting impacts upon the cost of capital for all of these parties--is affected by the terms of the utility's competitive procurement procedures, the contract between the utility and the IPP, and arrangements between the IPP and its suppliers. An IPP can reduce its capital costs if it shifts risk forward onto the utility or backward onto its suppliers. Here, for brevity, we consider only the former.

In most states utilities' competitive procurement procedures and utility contracts with IPPs would be subject to review and approval by state regulatory authorities. Competitive procurement procedures allocate risk between the IPP and the utility through a number of mechanisms. Some procurement programs, for example, require a minimum equity component for IPP participants. The utility usually enters into a long-term contract with an IPP to provide power, which ensures sales and revenue stability to the IPP and lowers its risk. Some utilities require the IPP to agree to contractual provisions giving the utility a right of "first refusal" to purchase the assets of the IPP should it become insolvent or cease to operate; this helps to reduce the risks transferred to the utility.

Moreover, competitive procurement programs do not necessarily choose the lowest cost bidder. The procedures used frequently incorporate various "non-cost factors" into the selection process to ensure protection of the public interest. These typically include such factors as fuel diversity (to ensure that the utility does not become over-dependent on a particular fuel for electric generation), environmental impacts, local employment impacts and other factors.

In addition, state commissions simply may limit utilities' reliance on outside sources of electric power (whether from IPPs or other suppliers) by requiring that utilities supply some minimum proportion of incremental supply requirements under traditional cost-of-service regulation. For example, the Virginia commission has used its authority in this respect with regard to power purchases by the Virginia Power Company.

The point is, issues of leveraged financing for IPPs are not new or unique to PUHCA reform. IPPs are a reality now. States have not indicated any difficulty in overseeing competition between IPPs and utilities, or in policing the use of debt by IPPs, should they choose to do so.

Conclusions

We draw four conclusions from this analysis:

1. We have no evidence that IPPs have a consistent cost-of-capital advantage over utilities, even where they are highly leveraged.

2. If a particular IPP has a lower cost of capital than a utility, this is a signal that the financial community has concluded that that IPP is less risky, from an investment standpoint, than the electric utility.

3. If state commissions are concerned about an undesirable cost-of-capital advantage to IPPs, they have the authority to adjust the competitive procurement process to shift risks in such a way as to correct this. If a state commission deems it important to limit the amount of debt its regulated utilities may incur, it seems unlikely that the same regulatory authority would allow dependence on power generated by IPPs with very high debt ratios to reach undesirable proportions.

4. Last and most important, there is no compelling reason for the Federal Government to prescribe how risks ought to be shared as between utilities and IPPs. Given the complex relationships between debt levels, cost of capital, and risk, we strongly believe that risk allocations and capital structures should be allowed to evolve naturally in this new market.

QUESTION FROM SENATOR BUMPERS

Question: A growing number of states have adopted competitive bidding programs for the acquisition of capacity by their native utilities. Such bidding programs are often and appropriately tied to least cost planning or integrated resource planning. More companies will be able to participate in these bidding programs as a result of this legislation.

How does the existence of a multi-state holding company with operating companies in each state affect the ability of the individual state commissions to require that their jurisdictional operating company --

1) Engage in integrated resource planning; and/or

2) Acquire new capacity through a competitive bidding process?

Answer: As a preface to answering this and the following questions related to jurisdiction over multi-state utility holding companies, we wish to state that the answers below are intended to describe--not endorse--the present regulatory structure.

The existence of a registered multi-state utility holding company would not affect the ability of a state commission to require a subsidiary operating utility company within the commission's jurisdiction to engage in integrated resource planning (IRP) or competitive bidding activities.

If IRP and/or competitive bidding activities are planned at the system level by a registered utility holding company, we believe that they become subject to FERC rather than state jurisdiction, though this has yet to be tested. Affected state commissions would then participate in an FERC proceeding where development and implementation of these system-wide programs would be addressed.

There may, however, be other issues to be resolved. For example, if a registered utility holding company fails to undertake system-wide IRP or competitive bidding, this could lead to unnecessarily high costs for an operating company. In turn, the affected state commission could assert that the extra costs had been imprudently incurred and that recovery of them by the operating company should be denied. Whether the operating company actually had the latitude to avoid these costs, however, could be difficult to determine.

The National Association of Regulatory Utility Commissions (NARUC) considered one possible approach to the subject of state versus Federal jurisdiction over registered utility holding companies at its winter meetings in Washington, DC this past February. NARUC's Executive Committee passed a resolution calling for legislative reform of the Federal Power Act to ensure that (1) state commissions retain authority over utility retail rates; and (2) the states are permitted to form, on a voluntary basis, regional regulatory agencies with the authority to address system-wide and regional planning and capacity acquisition activities. If the states do not form such regional agencies, authority to regulate system-wide or regional planning and acquisition activities would remain with the FERC.

Follow-up Question: Assuming that the states each have this authority over their jurisdictional operating company, what authority does each state have to require the holding company to do the same?

Answer: We believe that the states have no such authority with respect to registered utility holding companies.

Follow-up Question: Can any existing state or federal regulatory authority compel a multi-state holding company to engage in integrated resource planning or competitive bidding on a regional scale?

Answer: As stated above, it appears to us that the states have no direct authority with respect to registered utility holding companies. The Department believes that the FERC, in exercising its authority to regulate wholesale rates under existing law, can require such actions by registered utility holding companies.

Follow-up Question: Does regional planning and bidding make sense for an integrated multi-state system?

Answer: Yes. We believe that economic efficiencies and benefits for electricity consumers are obtainable through such planning for any pool, whether a holding company pool or a pool made up of unaffiliated firms.

Follow-up Question: Should we authorize the creation of regional regulatory entities for this purpose?

Answer: We do not take a position on the concept of regional regulatory entities. However, the challenges here are to ensure that the regional entities would be strong and effective institutions and that creating them would contribute to a simpler regulatory process in the electricity sector.

QUESTION FROM SENATOR WALLOP

Question: One key concern of utilities who oppose PUHCA legislation is that because IPPs can have a high debt ratio and interest is tax deductible, IPPs will have an artificial competitive advantage. What are the Department's views?

Answer: As we suggested in an insert to the record of the March 14 hearing (requested by Senator Wirth, attached), there does not appear to be a consistent cost of capital advantage to IPPs, whether resulting from the use of debt financing or other factors. If a particular IPP has a lower cost of capital than a utility, this is a signal that the financial community has concluded that that IPP is simply less risky, from an investment standpoint, than the electric utility.

However, if a state commission finds that IPPs are furnishing an unacceptably high proportion of new generating capacity, a commission can respond (and some have) by establishing both price and non-price factors to be considered in the development of competitive procurement procedures and power purchase agreements between utilities and IPPs. These factors may, and typically do, include such considerations as: (1) requiring a minimum equity fraction for IPPs; (2) providing the utility with a "first refusal" to purchase the assets of the

IPP should the IPP become insolvent or cease to operate; and (3) requiring a utility to limit its purchases of IPP power and provide some portion of incremental generation capacity under traditional cost-of-service regulation.

QUESTIONS FROM SENATOR NICKLES

Question 1: There are numerous natural gas producers who support PUHCA amendment under the theory that IPPs will often, if not usually, use gas as their burner fuel. On the other hand there are some who maintain that PUHCA amendment will produce little, if any increased gas usage because of existing IPP and cogeneration development under PUHCA and PURPA, the enactment of the Clean Air Act which provides de facto incentives to choose gas over coal, and the repeal of the last prohibition to utilities' use of gas under the Fuel Use Act. Has the Department been able to quantify the marginal volume of increased gas usage expected to be attributable to PUHCA amendment legislation over and above what is expected to occur in the future in the face of these three existing factors? If not, would you please provide such data to the Committee so we can sort out the natural gas industry impacts here?

Answer: The Department has not quantified the increased natural gas usage that would result from PUHCA amendment. However, it is reasonable to assume that the gas share of the market for generation fuel might increase, given the following data:

(1) At present, natural gas supplies about 9 percent of the energy used for U.S. electricity generation.

(2) About 40 percent of the new utility-owned capacity now planned by the utility industry (through 1999) is expected to be gas- or oil-fired; presumably, these are mostly gas or dual-fuel-capable units.

(3) Among the winning bids by non-utility producers to supply new electric generating capacity over a recent five-year period, natural gas captured about 45 percent of the market.

The strong interest by both utilities and non-utility producers in natural gas as a generation fuel reflects current and projected fuel prices. Given these projections, PUHCA amendment, which facilitates competition, may favor natural gas somewhat, and certainly would not disadvantage gas.

We have not tried to project the long-term impacts of PUHCA amendment on fuel mix, because to do so we would have to not only correctly project future fuel prices, but also outguess the effects of the competitive process on construction costs and technological innovation.

QUESTIONS FROM SENATOR NICKLES

Question 2: There is a split in the electric utility industry over the wisdom and practicality of the amendments to the Public Utility Holding Company Act. Proponents point to what they see as the economic attributes of enhanced competition. By the same token, opponents of the amendments argue that it is the cooperation inherent in the existing national electrical system that insures the reliability of service Americans have come to expect. This is a very important issue to which we must pay careful attention so that we don't jeopardize the reliability of electrical service.

How does the Administration envision integrating unregulated, decentralized independent power producers who have no utility obligation to serve the public into the existing cooperative, regulated national system without threatening that system's reliability? Do we need to know more about this issue? Would you share with the Committee whatever written analysis the Department and others in the Administration have prepared on this reliability issue?

Answer: There is no reason to think that contracts reflecting market forces are inferior to regulation in reliably supplying goods and services. It may be easier and less costly to build reliability incentives into power contracts than to achieve reliability through regulatory obligation, as experience with shortages in other regulated industries has shown.

Although IPPs have no direct obligation to serve the public, they have compelling business reasons to fulfill the terms of their contracts with utilities, who will remain regulated and who will retain the obligation to provide reliable service.

It is inaccurate, therefore, to think of IPPs as wholly independent agents. They produce a product which is to be sold into a utility-managed transmission and distribution system, and this system will still be carefully regulated by state and Federal authorities.

Within this regulatory framework, utilities will continue to have direct control over access to their transmission facilities by non-utility producers. It is common practice now to make a contract between a purchasing utility and a non-utility electricity supplier contingent on the supplier's agreement to operate according to the transmission control center's ground rules. Such ground rules will continue to be set by utilities working jointly through the regional councils of the North American Electric Reliability Council (NERC). Utilities will have ample opportunity to ensure that wholesale electricity trade does not evolve in ways that compromise reliability.

The Department addressed the question of impacts of amending PUHCA on reliability in Linda Stuntz' written statement for the Senate Energy Committee's hearing of March 14, 1991 (see pp. 19-23, attached). Also, see *National Energy Strategy*

Committee Note--The material submitted has been retained in Committee files.

Technical Annex No. 1, Analysis of Options to Amend the Public Utility Holding Company Act of 1935, pages 92-95 (copy attached).

Further, the question of whether there are technical obstacles to sustaining reliability in the context of increasing competition in wholesale electricity markets was addressed in 1989 in a major study by the Office of Technology Assessment, *Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition* (OTA-E-409, May 1989). The study concluded that there are no major *technical* obstacles to maintaining reliability under competition, while stressing that competition would induce many organizational changes. OTA found that these changes would have to be implemented carefully in order to maintain the level of coordination which reliability requires.

Committee Note--The material submitted has been retained in Committee files.

QUESTIONS FROM SENATOR NICKLES

Question 3: A. Is there anything in your legislation that would prevent an IPP from selling power directly to a retail customer of an existing utility?

Answer: Yes. It is explicitly blocked by the definition of an "exempt wholesale generator" (EWG), which is the term used in the proposal for a PUHCA-exempt independent power producer (IPP). Section 401 (1) defines an EWG as a person engaged "exclusively in the business of owning or operating all or part of one or more eligible facilities and selling electric energy at wholesale." Under Section 201(d) of the Federal Power Act, a wholesale sale requires a subsequent resale, and therefore direct sales to end-users are precluded in our proposal.

Follow-up Question: B. Is there anything in your legislation that would prevent an IPP from selling power directly to a wholesale purchaser who would in turn sell it to retail customers of an existing utility? For example, could a municipality, which is currently served by a utility, contract to buy the power from the IPP on a wholesale basis for resale to the citizens living in and the businesses operating in that municipality? If this is allowed, does it constitute "cherry picking" of the utility's best customers, leaving the rest of the retail accounts to pick up the utility's rate base in higher rates?

Answer: There is nothing in our proposed legislation that would prevent the situation you describe. However, it can occur under present law. That is, a municipality may arrange to withdraw from a given utility's service area, and create a municipal utility, with its own power production capacity, or capacity contracted from an independent or third party.

Our proposal to amend PUHCA does not affect this matter, and leaves it to be addressed (as it now) through state law and Federal antitrust law.

QUESTIONS FROM SENATOR NICKLES

Question 4: When Secretary Watkins appeared before this Committee in February to unveil the Administration's National Energy Strategy, I raised the point that there is serious question, arising even from the Administration's own research, as to whether PUHCA amendment is necessary to avert power supply shortages. For example, many observers, including the North American Electric Reliability Council, conclude that electric utilities generally have adequate plans to provide reliable electric service to their customers through the year 2000.

As I indicated, at that first hearing I raised this issue to Secretary Watkins and asked him to provide responses to the following question, specifically: Are IPPs necessary to avoid power supply shortages or are there already adequate supplies on line or in the planning stages from both utility plants and the non-utility plants being fostered by PURPA? I also asked the Secretary to provide the Committee with a copy of the Administration's study of this supply issue. To date, however, I have not received a response to my inquiry or my request for background information and I would hope you would answer my question.

Answer: We regret the delay in getting the Secretary's response to you. In answer to your question, we do not believe independent power producers, or any other particular kind of power producers, are "necessary to avert power supply shortages."

However, we do believe consumers will benefit from the lower costs that greater competition can provide. Under the Administration's PUHCA proposal, decisions of whether (or to what extent) to obtain new supplies through competitive procurement will continue to be the responsibility of utilities and their state regulators--just as they are today.

Concerning your request for background information, our NES Technical Annex No. 1, *Analysis of Options to Amend the Public Utility Holding Company Act of 1935*, contains much useful information on matters related to PUHCA amendment. It was circulated as an attachment to Linda Stuntz' written statement at the Senate Energy Committee's hearing on March 14, 1991.

QUESTION FROM SENATOR AKAKA

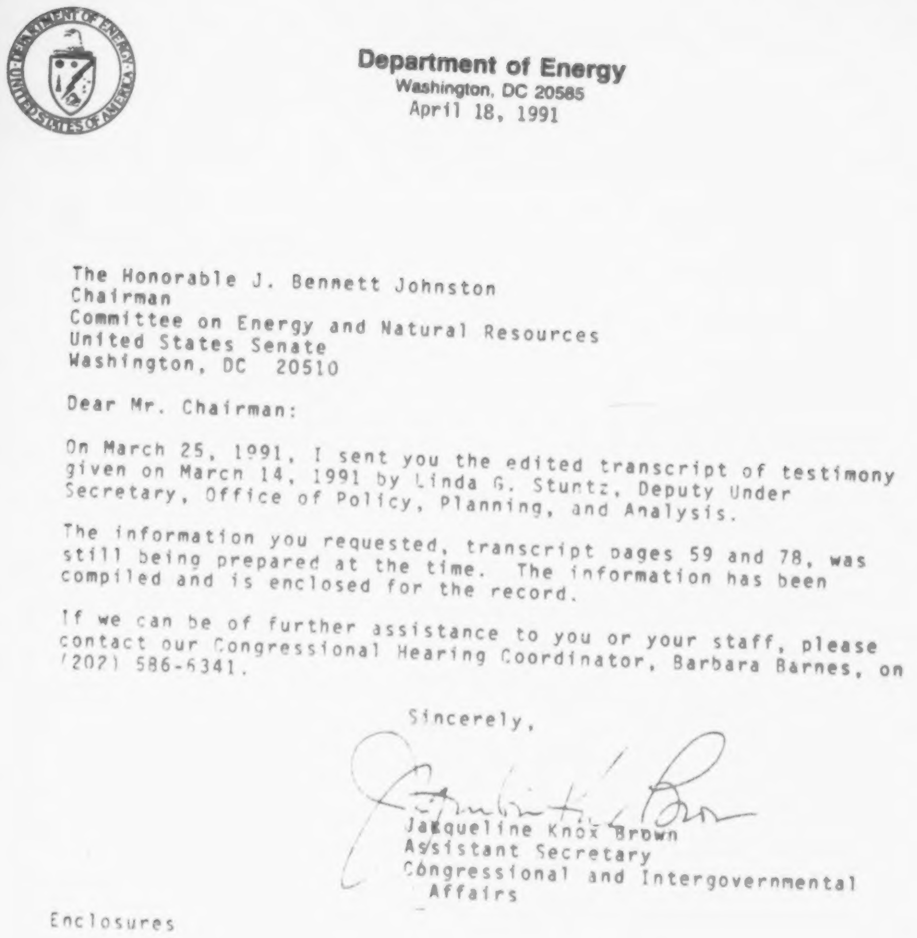
Question: Section 15001(a)(2) of S. 341 defines an "eligible facility" to be "a facility, *wheresoever located*, used for the generation of electric energy . . ." (Emphasis added.) Title IV of S. 570 contains an essentially similar provision.

Does the scope of the phrase "wheresoever located" and the corresponding term in Title IV of S. 570 extend to both foreign and domestic facilities?

Answer: Yes.

Follow-up Question: Assuming the enactment of PUHCA reform legislation contained in S. 341 or in S. 570, what further requirements, if any, would have to be satisfied in order for a holding company to own and operate an electric generation facility in a foreign country?

Answer: None, provided it sells only at wholesale.



Department of Energy
Washington, DC 20585

April 18, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

On March 25, 1991, I sent you the edited transcript of testimony given on March 14, 1991 by Linda G. Stuntz, Deputy Under Secretary, Office of Policy, Planning, and Analysis.

The information you requested, transcript pages 59 and 78, was still being prepared at the time. The information has been compiled and is enclosed for the record.

If we can be of further assistance to you or your staff, please contact our Congressional Hearing Coordinator, Barbara Barnes, on (202) 586-6341.

Sincerely,

Jacqueline Knox Brown
Assistant Secretary
Congressional and Intergovernmental
Affairs

Enclosures

Insert on Consumer Protection Measures

(Requested by Senator Conrad, transcript p. 59)

To display in a succinct form the consumer protection provisions in the Administration's PUHCA bill, we have prepared a matrix, which is provided as Table 1 below. The table depicts the bill's coverage of preferential self-dealing and cross-subsidy for each of the four categories of potential EWG/utility affiliate relationships.

The principal points to be drawn from the table are:

1. If the EWG is unaffiliated with a utility, the problems of preferential self-dealing and cross-subsidy do not arise.

2. In the other three types of relationships, FERC scrutiny of the selling price for "undue advantage" is always applicable, and State review of the purchaser's prudence is applicable except where FERC action has left the purchaser with no choice but to accept costs or power as allocated by FERC.

3. If the EWG is affiliated with a simple utility, the utility is regulated directly by the State(s), and the State(s) may obtain data as needed on the EWG through the utility as EWG parent.

4. In the case of EWGs affiliated with exempt holding companies, two additional protections are added: (a) EWG power sales to utility associates require prior State approval, and (b) retention of the holding company's exempt status requires the establishment of means of identifying cross-subsidies.

5. In the case of an EWG affiliated with a registered holding company, one additional protection is added: EWG power sales to utility associates require prior State approval. Problems of cross-subsidy can be addressed through review of cost data filed with the SEC.

Table 1. **Consumer Protection Provisions in Administration's Proposed PUHCA Amendment**

	Consumer Protections Against	
EWG/Utility Affiliate Relationship	**Preferential Self-Dealing**	**Cross-Subsidy**
A. No utility affiliation	No problem	No problem
B. Simple utility w/ EWG subsidiary	1. FERC "undue advantage" 2. State prudence 3. State regulates utility and subsidiary	1. State regulates utility and subsidiary
C. Exempt HC w/ EWG subsidiary	1. FERC "undue advantage" 2. State prudence 3. PUHCA exemption requires State prior approval of power sales to associates	1. PUHCA exemption requires HC to set up means of detecting cross-subsidy
D. Registered HC w/ EWG subsidiary	1. FERC "undue advantage" 2. State prudence (unless FERC pre-empts) 3. EWG ownership requires State prior approval of power sales to associates	1. Cost data filed with SEC

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF THE GENERAL COUNSEL

April 8, 1991

Honorable J. Bennett Johnston
Chairman
Committee on Energy and
  Natural Resources
United States Senate
Washington, DC 20510-6150

Dear Senator Johnston:

Pursuant to your letter of March 20, 1991 to Cynthia A. Marlette, attached are answers to questions for the printed hearing record from Senators Bumpers, Nickles and Akaka concerning Title XV of S.341 and Title IV of S.570.

If any additional information is required, please feel free to call me or Ms. Marlette.

Sincerely,

William

William S. Scherman
General Counsel

Questions Submitted by Senator Bumpers
Re: Title XV of S. 341 and Title IV of S. 570

Question: A growing number of states have adopted competitive bidding programs for the acquisition of capacity by their native utilities. Such bidding programs are often and appropriately tied to least cost planning or integrated resource planning. More companies will be able to participate in these bidding programs as a result of this legislation.

How does the existence of a multi-state holding company with operating companies in each state affect the ability of the individual state commissions to require that their jurisdictional operation company --

1) engage in integrated resource planning; and/or

2) acquire new capacity through a competitive bidding process?

Answer: As a general matter, the existence of a multi-state holding company with operating companies in several states would not preclude individual state commissions from requiring their jurisdictional operating companies to engage in integrated resource planning and/or to acquire new capacity through a competitive bidding process. However, as discussed below, there are circumstances where a state commission's authority will be affected.

Because the operating companies of integrated holding company systems plan new capacity based on an overall system plan, for the benefit of the system as a whole, capacity acquisitions -- whether through self-building of new generation units or through power purchases from others -- may be the subject of agreements governing or affecting integrated operations and rates for wholesale sales in interstate commerce. Such agreements are subject to FERC and/or SEC jurisdiction. Because the FERC has exclusive authority over wholesale interstate rates and cost allocations affecting wholesale rates, and has jurisdiction to review whether costs supporting proposed rates were prudently incurred and whether rates and allocations involving multi-state operating companies are non-discriminatory, state decisions regarding integrated resource planning and competitive procurement could be affected or preempted under existing federal law by federal ratemaking decisions. (See Mississippi Power and Light Co. v. Moore, 487 U.S. 354 (1988)). However, whether a state decision regarding integrated resource planning and competitive procurement would be preempted would depend upon the specific terms of the interstate agreements under which the operating companies integrate facilities, implement system planning, establish rates and allocate costs, and the specifics of the federal decision determining wholesale rates. As a general matter, FERC ratemaking decisions are not likely to conflict or interfere with state decisions involving integrated resource planning or competitive bidding.

It should be emphasized that the very nature of multi-state holding company systems, having operating companies in several states, lends itself to system integrated resource planning (IRP), as opposed to individual member IRP. Indeed, the very reason for creating such holding companies is to capture the benefits and economies of regional integration of facilities and systemwide planning.

Although states have understandable concerns over local utilities that join multi-state holding companies or power pools, it must be recognized that the reason states allow those utilities to join multi-state systems is to capture the benefits of multi-state integration in order to better serve the utilities' native load ratepayers in the respective states. One of the trade-offs in obtaining these efficiencies is that some of the regulation of the utilities moves from the local to the federal arena. Importantly, if and when this occurs, states clearly have a forum at the federal level (both the SEC and the FERC) to make their views and concerns known. For example, state commissions and state public consumer advocates often intervene and participate in FERC proceedings. In addition, in situations where there is disagreement among states, a federal arbiter is in the best position to reach a result that is fair to all affected states, rather than to be controlled by the particular concerns of any one individual state. Thus, to the extent Congress were to modify the existing line between federal and state jurisdiction, serious public policy concerns would be raised. Indeed, it is unclear whether the existing national benefits that result from the current allocation of jurisdictional responsibilities would continue if significant modifications were made to the Federal Power Act.

Question: Assuming that the states each have this authority over their jurisdictional operating company, what authority does each state have to require the holding company to do the same?

Answer: States generally do not have jurisdiction over holding companies. Rather, state jurisdiction is typically limited to the "public utility" operating companies of holding company systems. However, to the extent holding companies are also "public utilities" as defined by state law, states would have direct authority to require holding companies to engage in IRP or competitive bidding.

Question: Can any existing state or federal regulatory authority compel a multi-state holding company to engage in integrated resource planning or competitive bidding on a regional scale?

Answer: Only in those instances where a holding company is also a public utility, as defined by state law or the Federal Power Act, respectively, would state regulatory commissions and the FERC have the direct authority to compel a multi-state holding company to engage in IRP or in competitive bidding on a regional scale.

However, even if there is not direct authority over a holding company itself, the FERC would have authority over multi-state agreements among the operating companies of the holding company, and could find that such agreements that are inconsistent with system IRP or least-cost planning are unjust and unreasonable. Such a finding would, in the long term, encourage competitive procurement (bidding or negotiation) by the holding company system.

Moreover, where regulatory approval is required to finance new construction, state regulatory commissions and/or the FERC could require compliance with IRP in order to obtain regulatory approval for issuance of securities to finance such construction. Similarly, it would appear that SEC authorization for such financing by a registered holding company could also address IRP issues.

Question: Does regional planning and bidding make sense for an integrated multi-state system?

Answer: Regional planning and regional competitive procurement (whether by bidding or negotiation) makes very good sense for an integrated multi-state system because, as explained above, the purpose of such integration is to obtain power for the benefit of the system as a whole.

Question: Should we authorize the creation of regional regulatory entities for this purpose?

Answer: As discussed earlier, it is not clear how effective regional regulatory entities would be. Under existing state/federal law, state commissions can seek agreement among themselves regarding multi-state issues and, where interstate wholesale rates and matters affecting rates are involved, present their agreement and recommendations to the FERC. Such agreements accomplish the same purpose that regional regulatory authorities would accomplish, and are given great weight in FERC proceedings. Thus, it is unclear whether benefits would be derived from creating another level of regulation that a regional regulatory body would represent.

In considering whether to create regional regulatory entities, the question that must be asked is whether such entities would indeed be able to resolve multi-state conflicts more effectively (if at all) than can a neutral Federal arbiter, and whether it could be done expeditiously. In addition, some planning decisions, especially those regarding transmission facilities, can have impacts (e.g. loop flows) on parties located outside the service territory of the multi-state holding company. It is unclear how regional regulatory entities could be structured to ensure adequate representation of these interests.

Questions Submitted by Senator Nickles
Re: Title XV of S. 341

Question: There are numerous natural gas producers who support PUHCA amendment under the theory that IPPs will often, if not usually, use gas as their burner fuel. On the other hand there are some who maintain that PUHCA amendment will produce little, if any, increased gas usage because of existing IPP and cogeneration development under PUHCA and PURPA, the enactment of the Clean Air Act which provides de facto incentives to choose gas over coal, and the repeal of the last prohibition to utilities' use of gas under the Fuel Use Act. Has the Department been able to quantify the marginal volume of increased gas usage expected to be attributable to PUHCA amendment legislation over and above what is expected to occur in the future in the face of these three existing factors? If not, would you please provide such data to the Committee so we can sort out the natural gas industry impacts here?

Answer: The FERC staff has not analyzed the impacts of PUHCA on the natural gas industry nor does it have the necessary data to perform such an analysis. However, we share the view of many other forecasters that there will be at least some increase in gas demand as a result of increasing the options available for new generation that PUHCA reform will bring.

Question: There is a split in the electric utility industry over the wisdom and practicality of the amendments to the Public Utility Holding Company Act. Proponents point to what they see as the economic attributes of enhanced competition. By the same token, opponents of the amendments argue that it is the cooperation inherent in the existing national electrical system that ensures the reliability of service Americans have come to expect. This is a very important issue to which we must pay careful attention so that we don't jeopardize the reliability of electrical service.

How does the Administration envision intagrating unregulated, decentralized independent power producers who have no utility obligation to serve the public into the existing cooperative, regulated national system without threatening that system's reliability? Do we need to know more about this issue? Would you share with the Committee whatever written analysis the Department and others in the Administration have prepared on this reliability issue?

Answer: As a preliminary matter, it is extremely unlikely that any independent power producer will be unregulated. Most IPPs will be public utilities subject to FERC regulation under the Federal Power Act. Public utilities subject to FERC regulation, whether IPPs or traditional utilities, do not have any express wholesale obligation to serve; rather, in all FERC-jurisdictional wholesale transactions, the "obligation to serve" stems from contractual arrangements that must be approved by the Commission and that cannot terminate absent Commission approval.

Importantly, available evidence does not suggest that IPP generation will be any less reliable than traditional utility generation. In its study, Electric Power Wheeling and Dealing, the Office of Technology Assessment, while noting that there may need to be some institutional and procedural changes in the way the industry operates, found that there are no insurmountable technical problems with integrating IPPs into the industry.

Further, available evidence indicates that non-utility generating plants are no less reliable than utility plants. Since the Public Utility Regulatory Policies Act was passed in 1978, some 30,000 megawatts of non-utility generation has come into production. The reliability of these PURPA qualifying facilities has been as good, if not better, than the plants owned by utilities they sell to. This is not unexpected because QFs use the same equipment suppliers (e.g. General Electric, Westinghouse) and builders (e.g., Bechtel) that traditional utilities use. Moreover, non-utility QFs and other non-traditional generators (e.g., IPPs) have more financial pressure than traditional utilities do to keep their plants up and running -- QFs and IPPs typically do not get paid if their plants are unavailable, whereas traditional utilities usually recover the capital costs of a unit even if it is out of service.

QFs provided reliable service during the periods involving the 1989 San Francisco earthquake and last year's severe winter weather in Texas and Florida. The dispersed location of QF plants proved especially important in permitting the restoration of service in California following the earthquake. Utilities with substantial QF suppliers in other states report high marks for QF availability and reliability.

It is important to keep in mind that, unlike the obligation of traditional utilities to purchase from QFs under PURPA, traditional utilities would not be required to purchase from IPPs if the Holding Company Act is amended. While changes in the Holding Company Act will remove antiquated barriers and may make it possible for more independent power producers to come into existence, traditional utilities will continue to plan and control whether to purchase IPP power and the amounts, if any, of such purchases, and the way such power is managed and integrated into the bulk power system. Therefore, utilities would continue to control the desired mix of power from various sources.

Finally, a utility's contractual control of purchases does not depend on price terms alone. Utilities often specify the technology and fuel mix of the generators and include earnest money, contract guarantees, construction milestones and periodic inspections in their purchase contracts. These contract terms are designed, in part, to ensure reliable operation. Moreover, both state sanctioned and non-sanctioned utility bidding programs typically factor these types of reliability-enhancing factors into the ranking criteria used to select winning bidders for new capacity.

Questions Submitted by Senator Akaka
Re: Title XV of S. 341

__Question__: Does the scope of the phrase "wheresoever located" and the corresponding term in Title IV of S. 570 extend to both foreign and domestic facilities?

__Answer__: The phrase appears to extend to both foreign and domestic facilities.

__Question__: Assuming the enactment of PUHCA reform legislation contained in S. 341 or S. 570, what further requirements, if any, would have to be satisfied in order for a holding company to own and operate an electric generation facility in a foreign country?

__Answer__: The FERC defers to the SEC as to any further requirements that would have to be satisfied under PUHCA.

As to requirements that would have to be satisfied under the Federal Power Act (FPA), as explained below, there is a possibility that FPA regulation would apply to holding company systems that own or operate foreign facilities whose power is sold into the United States. Such regulation would include regulation of rates for wholesale sales of electric energy and transmission in interstate commerce, and corporate and accounting regulation.

The FERC regulates public utilities as defined in the FPA. Under Sections 201(b) and (e) of the FPA, a public utility is any person who owns or operates facilities used for transmission or sales of electric energy for resale in interstate commerce. Under Section 202(f) of the FPA, the ownership or operation of facilities for transmission or sale at wholesale of electric energy which is generated in a foreign country and transmitted across an international boundary into a State __and not thereafter transmitted into any other State__ shall not make a person a public utility subject to regulation under the FPA. Thus, where foreign power is transmitted into only one State, the holding company owning the facility generating the power and the entity transmitting the power (assuming they own no other jurisdictional facilities) would not be subject to FPA regulation. However, where foreign power is transmitted across an international boundary into a State and thereafter transmitted into one or more additional states, the entity owning the facility or transmitting the power would be a public utility subject to regulation under the FPA, and the rates for the generation sale from the foreign facility would be subject to FERC approval.

J. BENNETT JOHNSTON, LOUISIANA, CHAIRMAN

DALE BUMPERS, ARKANSAS
WENDELL H. FORD, KENTUCKY
BILL BRADLEY, NEW JERSEY
JEFF BINGAMAN, NEW MEXICO
TIMOTHY E. WIRTH, COLORADO
KENT CONRAD, NORTH DAKOTA
DANIEL K. AKAKA, HAWAII
WYCHE FOWLER, JR., GEORGIA
RICHARD C. SHELBY, ALABAMA
PAUL WELLSTONE, MINNESOTA

MALCOLM WALLOP, WYOMING
MARK O. HATFIELD, OREGON
PETE V. DOMENICI, NEW MEXICO
FRANK H. MURKOWSKI, ALASKA
DON NICKLES, OKLAHOMA
CONRAD BURNS, MONTANA
LARRY E. CRAIG, IDAHO
JOHN SEYMOUR, CALIFORNIA
JAKE GARN, UTAH

BENJAMIN S. COOPER, STAFF DIRECTOR
D. MICHAEL HARVEY, CHIEF COUNSEL
G. ROBERT WALLACE, STAFF DIRECTOR FOR THE MINORITY
GARY G. ELLSWORTH, CHIEF COUNSEL FOR THE MINORITY

United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150

March 20, 1991

Mr. Scott Hempling, Esq.
1819 H Street, N.W.
Suite 500
Washington, D.C. 20006

Dear Mr. Hempling:

Thank you for presenting testimony before the Full Committee on Energy and Natural Resources on S. 341, the National Energy Security Act of 1991, Title XV, concerning reform of the Public Utility Holding Company Act of 1935 (PUHCA).

As a follow-up to the hearing, I have enclosed questions for the printed hearing record. I request that the answers to these questions be provided to the Committee no later than April 5, 1991.

If you have any questions concerning this request, please contact Bill Conway at (202) 224-7149.

Sincerely,

J. Bennett Johnston
J. Bennett Johnston
Chairman

JBJ/wbc

Enclosure

Questions submitted for the Record
Hearing on Title XV of S. 341 and Title IV of S. 570
Senator Dale Bumpers

Please submit the following series of questions to the witnesses representing DOE, FERC, City of New Orleans, Registered Holding Companies, Environmental Action and Consumer Federation of America

A growing number of states have adopted competitive bidding programs for the acquisition of capacity by their native utilities. Such bidding programs are often and appropriately tied to least cost planning or integrated resource planning. More companies will be able to participate in these bidding programs as a result of this legislation.

How does the existence of a multi-state holding company with operating companies in each state affect the ability of the individual state commissions to require that their jurisdictional operating company --

1) engage in integrated resource planning; and/or

2) acquire new capacity through a competitive bidding process?

Assuming that the states each have this authority over their jurisdictional operating company, what authority does each state have to require the holding company to do the same?

Can any existing state or federal regulatory authority compel a multi-state holding company to engage in integrated resource planning or competitive bidding on a regional scale?

Does regional planning and bidding make sense for an integrated multi-state system?

Should we authorize the creation of regional regulatory entities for this purpose?

May 7, 1991

The Honorable Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C.

Dear Chairman Johnston:

On behalf of Environmental Action Foundation (EAF), I submit answers to the questions posed by Senator Bumpers concerning state competitive bidding programs, integrated resource planning, and multistate holding company systems.

The first paragraph in the questions states that "[m]ore companies will be able to participate in these bidding programs as a result of [Title XV]." We cannot accept this premise as a given. The proponents of Title XV hope that a weakened Public Utility Holding Company Act will increase the number of players in wholesale markets. But utility refusals to provide fair access to the transmission highways likely will produce a future in which a small number of very large players -- not "more" players -- dominate wholesale markets. Title XV's failure to confront the transmission issue seals this result.

1. The first question asks how the existence of a multistate holding company affects a state commission's ability to require the individual utility company subject to its jurisdiction to (1) engage in integrated resource planning or (2) acquire new capacity through a competitive bidding process. The answer is, in a word, deeply.

A state commission may influence the decisions of a utility company only when the utility can make decisions on its own. A state may wish to urge its utility to substitute conservation or load management for construction of new generation. Alternatively, the state may prefer, on environmental grounds, that its utility buy from gas-fired cogeneration rather than construct a coal-fired plant. These kinds of decisions constitute the essence of integrated resource planning.

In the type of multistate holding company system described in the U.S. Supreme Court case Mississippi Power & Light v. State of Mississippi ex rel. Moore, the individual utility's subsidiaries were prevented legally from making most planning decisions on their own. The mere filing by the holding company system of a System Agreement at the Federal Energy Regulatory Commission (FERC), and its acceptance by FERC, erased any decisionmaking autonomy of the part of each utility subsidiary.

If an individual utility cannot make decisions on its own, a state commission has no opportunity to guide that individual utility's planning practices.

This constriction of traditional state commission practice is a direct outgrowth of the present Federal Power Act treatment of centrally planned holding company systems. True integrated resource planning and competitive bidding in states regulating utility members of such systems cannot take place without amending Federal law.

2. The second question suspends the existing legal context, and assumes a state has authority to impose competitive bidding or integrated resource planning over its jurisdictional utility. The questions asks whether the state has authority to require the holding company, as distinct from the operating utility, to participate in competitive bidding or integrated resource planning. This result does not seem logically possible. For a particular state to direct or guide the activities of a holding company system serving more than one state would be to invite conflicting directives.

3. As explained in the preceeding paragraph, it does not appear that an existing state regulatory authority could "compel a multistate holding company to engage in integrated resource planning or competitive bidding on a regional scale." Could a federal regulatory authority do so?

The best answer is that an effort by FERC to do so would likely provoke substantial litigation over FERC's authority. Therefore, it would be better for Congress to create such authority in FERC rather than assume it exists.

For example, I would argue that FERC has such authority today under Sections 205 and 206 of the Federal Power Act. Those provisions require FERC to ensure that wholesale rates charged by utilities, including utilities affiliated with holding company systems, are "just and reasonable." Rates are not just and reasonable when based on costs rendered artificially high by a utility's imprudence. I would argue that a holding company system has behaved imprudently when it does not engage in integrated resource planning or competitive bidding. Under these facts, FERC must find imprudence and declare the rates to be unjust and unreasonable. And, if FERC is authorized to declare rates unjust and unreasonable based on the utility's failure to engage in integrated resource planning or competitive bidding, then it has the authority to insist on such practices at the outset.

On the other hand, utilities might argue that, under Section 201, FERC does not have authority over "generating facilities." If FERC does not have such authority, the argument would go, it cannot compel utility decisions involving generating facilities.

Since integrated resource planning and competitive bidding involve generating facilities intimately, FERC can have no authority to mandate such practices.

As I discussed above, if Congress wants integrated resource planning and competitive bidding on a regional basis, it should clarify FERC's authority to mandate these activities. Otherwise, the industry's future will remain uncertain, and efficiencies will be foregone as companies, consumers and regulators litigate (probably to the U.S. Supreme Court again) the question of FERC's authority.

4. The fourth question asks whether regional plannnig and bidding make sense for an integrated multistate system. Regional planning and bidding make sense inherently, whether conducted by a single multistate system or by unaffiliated utilities. All utilities should engage in these activities as a matter of prudent utility practice. In today's electric industry, wholesale power supply markets are regional markets. If a utility is going to operate on a least cost basis (as required by traditional regulatory principles, and as would be required by the forces of competition if competition existed at retail), then that utility must engage in integrated planning and bidding on a regional basis.

That does not mean that a multistate holding company system should conduct regional planning only among its members, and not with other, unaffiliated utilities. As the Arkansas Public Service Commission wrote in testimony prepared for the March 13, 1991 hearing before the Senate Committee on Energy and Natural Resources (at p. 18):

> [r]egistered holding companies are historical accidents. Congress' intent in enacting PUHCA in 1935 was to break up the 13 holding companies which controlled the industry into local utility systems. In the long process of litigationthat accomplished this result, certain entitites managed to remain large and spread over several states. In today's industry any individual subsidiary of a multistate company may be able to coordinate and plan with adjacent unaffiliated utilities just as easily as they can coordinate and plan with the affiliated utilities in their registered system. There is some risk that by effectively requireing subsidiaries to coordinate with their affiliates, we forego more efficient coordination with the non affiliates. We should make these coordination and planning decisions on a case-by-case basis, rather than be ruled by system boundaries mapped out 40 and 50 years ago.

(Emphasis in original)

5. The last question asks whether Congress should authorize

the creation of regional regulatory entities for the purpose of mandating integrated resource planning and competitive bidding. Someone has to have this authority. Whether it is the state commissions, FERC or some new regional authority, depends on what activities we are trying to encourage. If we want each individual utility to seek to form the most efficient coordination arrangements with its neighbors, then we can rely on traditional state commission prudence authority, provided we overruled Mississippi Power & Light and ignore the artificial corporate boundaries of existing holding companies. If on the other hand, we want to view the existing corporate boundaries as rational planning regions, then individual states cannot easily perform this task.

We are looking closely at the concept of regional regulation. We believe that the Arkansas Public Service Commission, in the document quoted above, lists substantial questions with this approach. See pp. 17-21. We are working closely with consumers and states in areas presently served by multistate holding companies to determine the best approach. One thing is clear, however: the legal status quo, which invites utilities to shop for the most favorable forum is unsupportable on ground of logic, policy and fairness.

EAF appreciates th opportunity to testify before your Committee and to present its additional views at this time. We would be pleased to answer any additional questions from the Committee.

Sincerely,

Scott Hempling

HOUSTON LIGHTING & POWER COMPANY
P.O. BOX 1700
HOUSTON, TEXAS 77251

DON D. JORDAN
CHAIRMAN
AND
CHIEF EXECUTIVE OFFICER

April 3, 1991

The Honorable Bennett Johnston
United States Senate
Washington, DC 20510

Dear Senator Johnston:

Attached is my response to your follow-up questions regarding my March 14 testimony before the Senate Energy and Natural Resources Committee.

Throughout this debate I have argued that the creation of a new class of unregulated power producers will adversely affect the nation's consumers and electric supply system. My position is based on years of experience with purchased power, and my response to your questions includes vivid examples of how reliance on non-utility generation has increased consumer costs and threatened the reliability of electricity service.

In 1989, when Hurricane Gilbert threatened the Texas Gulf Coast, many of the non-utility generators prepared to shut down despite the fact that the hurricane was more than 700 miles from our area. This demonstrates that under adverse circumstances, non-utility generators, lacking a statutory obligation to serve, can and will shut down. Exhibits 1 and 2 describe the series of events which occurred during the Gilbert incident. These exhibits substantiate my testimony that non-utility generators were preparing to shut down, and in fact one did shut down, while HL&P was getting ready to weather the storm.

The regulated utility's statutory obligation to serve the consumer is not taken lightly. It is a guiding principle in how regulated utilities conduct their business. The primary objective of non-utility generators, however, is profit maximization. Our experiences with non-utility generation demonstrate that when profit maximization and service are not compatible - profit maximization, not service to the consumer - will be the winner. Exhibits 3 and 4 of my response illustrate this point. Recently, HL&P gave a major non-utility generator providing power to HL&P notice of termination as provided in our contract. HL&P also offered to pursue new contract discussions based on our current generation alternatives. The non-utility generator responded by suggesting that we were precluded from not renewing the existing contract at a cost to our customers in excess of $400 million over other available options.

The Honorable Senator Bennett Johnston
April 3, 1991
Page 2

The experiences of my company, not speculation or theory, convince me that the desire of non-utility generators to pursue unregulated profits will invariably divert benefits away from the electricity consumer to the non-utility generator.

I appreciate this opportunity to respond to your questions and to complement the hearing record with additional information. It is through this exchange of ideas that I believe the truth about non-utility generation will be exposed. I hope you and the members of your committee will feel free to ask me additional questions regarding our experiences with non-utility generation.

Sincerely,

Don D. Jordan

DDJ/mef

Enclosures

cc:
Sen. Daniel K. Akaka
Sen. Jeff Bingaman
Sen. Bill Bradley
Sen. Dale Bumpers
Sen. Conrad Burns
Sen. Kent Conrad
Sen. Larry E. Craig
Sen. Pete V. Domenici
Sen. Wyche Fowler, Jr.
Sen. Jake Garn
Sen. Mark O. Hatfield
Sen. Frank H. Murkowski
Sen. Don Nickles
Sen. John Seymour
Sen. Richard C. Shelby
Sen. Malcolm Wallop
Sen. Paul Wellstone
Sen. Tim Wirth
Sen. Phil Gramm
Sen. Lloyd Bentsen
Rep. Jack Fields
Rep. Jim Chapman
Rep. Charles Wilson
Rep. Steve Bartlett
Rep. Ralph M. Hall
Rep. John Bryant
Rep. Joe Barton
Rep. Bill Archer
Rep. Jack Brooks
Rep. J. J. Pickle
Rep. Chet Edwards
Rep. Pete Geren
Rep. Bill Sarpalius
Rep. Greg Laughlin
Rep. E. Kika de la Garza
Rep. Ronald D. Coleman
Rep. Charles W. Stenholm
Rep. Craig Washington
Rep. Larry Combest
Rep. Henry B. Gonzalez

Rep. Lamar S. Smith
Rep. Tom Delay
Rep. Albert G. Bustamante
Rep. Martin Frost
Rep. Michael A. Andrews
Rep. Richard K. Armey
Rep. Solomon P. Ortiz
Rep. Philip R. Sharp
Rep. W. J. "Billy" Tauzin
Rep. Jim Cooper
Rep. Terry L. Bruce
Rep. Edolphus Towns
Rep. C. Thomas McMillen
Rep. Gerry E. Studds
Rep. Richard H. Lehman
Rep. Dennis E. Eckart
Rep. Bill Richardson
Rep. Jim Slattery
Rep. Gerry Sikorski
Rep. Don Ritter
Rep. Thomas J. Bliley, Jr.
Rep. Michael Bilirakis
Rep. Dan Schaefer
Rep. Ron Wyden
Rep. Peter H. Kostmayer
Rep. Claude Harris
Rep. James H. Scheuer
Rep. Edward J. Markey
Rep. Al Swift
Rep. Mike Synar
Rep. John D. Dingell
Rep. Carlos J. Moorhead
Rep. William E. Dannemeyer
Rep. Michael G. Oxley
Rep. Sonny Callahan
Rep. Dennis Hastert
Rep. Clyde C. Halloway
Rep. Norman F. Lent
Rep. Henry A. Waxman
Rep. Cardiss Collins
Rep. Rick Boucher
Rep. J. Roy Rowland
Rep. Thomas J. Manton
Rep. Edward Madigan
Rep. Matthew J. Rinaldo
Rep. Alex McMillan
Roger Porter
Steve Brobeck
Mark Cooper

QUESTION RESPONSES

Question No. 1 - In your written testimony you refer to the fact that certain of your cogenerators sought to rely on force majeure provisions in their contracts during the approach of Hurricane Gilbert in 1988.

Do you agree that a hurricane can constitute force majeure? If not what would? Please comment upon the following account of the Hurricane Gilbert emergency. Is it accurate? If not, how is it inaccurate?

> Information available now indicates cogenerated power in HL&P's service area continued without interruption during the storm threat and in some cases cogenerators actually increased their net energy flows to the utility. Further, gas supplies to Texas cogenerators appeared to be more reliable than HL&P's offshore natural gas suppliers, which were forced to interrupt deliveries, causing shutdown of some of HL&P's thermal generation. In some cases cogenerators were unable to deliver electricity due to the loss of the utility's transmission lines, but overall the independent cogenerators provided critical backup electricity during this emergency. (Jan Hamrin, "Nonutility Power and the Reliability Issue", The Electricity Journal (June 1989), p. 17-18).

Response - Whether or not a hurricane constitutes force majeure is really not the issue in this case, since Hurricane Gilbert did not even reach Texas much less Houston. The real issue is commitment to the consumer. Will every possible measure be taken to ensure that electricity will be provided regardless of circumstance? The events which transpired during the threat of Hurricane Gilbert clearly demonstrate that cogenerators' commitment is not to the consumer but to their own operations. Non-utility generators site, design and construct, and operate plants to minimize cost and to maximize profits for the developer.

On the other hand, regulated electric utilities such as Houston Lighting & Power Company have a statutory obligation to serve. Because of our commitment to the consumer, we cannot abandon our charge to provide service. Consequently, we site, design, construct and operate our facilities to provide service under all conditions. Utility constructed plants are sited based on a number of factors which directly affect the efficiency and reliability of a facility. In siting our plants, we consider the proximity to load centers and transmission line requirements. When designing and constructing our plants, we incorporate redundancies in many components such as valves, boilers, feeder pumps, fans, etc. to ensure reliability under adverse conditions. In hurricane prone areas, we have built our plants well above grade at considerable expense to ensure our ability to withstand the high waters of storm surge. Finally, utilities make operational decisions based on system-wide efficiencies; whereas, a non-utility generator's only concern is selling kilowatts. Therefore, while cogenerators on our system were making plans to declare force majeure, we were making preparations to continue operating during the storm including shipping food, blankets and other living supplies into our plants so that operators could ride out the storm.

With regard to the account of the circumstances surrounding Hurricane Gilbert, it leaves the impression that cogenerators kept the HL&P system from failing. To the contrary, HL&P did not experience serious system emergencies since the hurricane never reached Texas. Yes, cogenerated power continued to flow, and if you will refer to my testimony regarding the profits they are earning, you can understand why.

What actually happened is that as Hurricane Gilbert crossed the Caribbean, natural gas producers began shutting down and evacuating their off-shore platforms. As the storm entered the Gulf and moved toward Mexico, cogenerators in Southeast Texas, where there is more cogeneration than anywhere else in the country, began notifying their customers of their intent to declare force majeure and shut down their generation. These customers included three of the state's largest utilities. The notices began two days before the estimated landfall of Gilbert during bright, sunny weather. In contrast, the utilities were busy making adjustments to ensure the continued delivery of electric power to their service territories in the event the storm turned northward toward Texas.

The hurricane eventually turned south, failing to make landfall on the Texas coast or even to come within 400 miles of area cogenerators. While only one of the area cogenerators actually shut down, the intent of the others was clear. The incident clearly illustrates the potential problem of overdependence on non-utility generation. No contract can guarantee or impose an ongoing obligation to serve. Electric utilities recognize the problem and have used the Gilbert account to illustrate the importance of having a reliable energy source.

A more detailed discussion of the events surrounding Hurricane Gilbert may be found in the following attachments:

Letter from Mr. R. J. Snokhous on behalf of HL&P to Mr. William Conway, Senior Counsel, U. S. Senate Committee on Energy and Natural Resources dated March 30, 1989.

Letter from Mr. L. G. Brackeen on behalf of HL&P to Mr. Joe Brunt of Dow Chemical dated October 22, 1988.

Question No. 2 - You indicated that one cogenerator has claimed in a letter that HL&P must continue an expensive power purchase with the cogenerator past the contract term. Please provide a copy of the letter.

Response - Attached is a letter from Mr. R. E. Baker of Occidental Chemical to Mr. L. G. Brackeen of HL&P. Despite the fact that OxyChem's proposed contract extension would cost HL&P's consumers millions of dollars more than other available alternatives, and that the contract specifically allows either party to terminate at the end of its initial term, OxyChem has attempted to unilaterally extend their current contract and preserve the maximum profitability of the arrangement - regardless of the negative effects that such a contract would have on the consumer.

Also attached is a letter from HL&P's L. G. Brackeen in response to Mr. Baker's letter stating that we will not extend a contract which will cost our consumers over $400 million more than other available alternatives. The chart attached to Mr. Brackeen's letter graphically depicts the enormous costs to the consumers associated with any extension of that contract.

- EXHIBIT 1 -
(PAGE 1 OF 2)

HOUSTON LIGHTING & POWER COMPANY
P. O. BOX 1700
HOUSTON, TEXAS 77001

R. J. [illegible]
Group Vice President

March 30, 1989

Mr. William B. Conway, Jr.
Senior Counsel, Committee on Energy
and Natural Resources
United States Senate
Washington, D.C. 20510-6150

Dear Bill:

It was a pleasure to visit with you again at the PRAG meeting March 20. Our conversation about non-utility generators, particularly Houston Lighting & Power Company's experience with cogenerators last year during our annual hurricane season, is the subject of this letter and the attachments.

HL&P's primary concern over electric industry structure matters has been the long-term reliability of power supplies from non-utility producers. For decades we and other utilities have had the responsibility of supplying power to our service areas under all conditions, whether during wartime or peace, prosperity or depression, good business conditions or bad. We are concerned that utilities might in future years be forced to depend on independent power producers for much of the electricity we deliver to our customers, but that those producers will not have the obligation or incentive to continue operating when conditions become unfavorable or unprofitable.

We have heard the counter-arguments to this concern, but remain unconvinced. We do not believe that contractual obligations can substitute for the obligation to serve. It is incomprehensible today, as we see contracts broken regularly and performance replaced by legal exercises, that the future of our nation's electric supply could be based on contracts.

All this is, however, academic until the circumstance occurs in which reliability is truly tested. Our recent experience -- the Hurricane Gilbert incident in September 1988 which you have heard about -- has reinforced our concerns. The situation demonstrated the lack of ability or willingness by non-utility generators to serve under adverse conditions.

It was not, as you have been told, only two cogenerators which gave notice of intent to shut down. As Hurricane Gilbert moved across the Yucatan Peninsula, every major cogenerator in the Houston area told HL&P's dispatchers they would shut down completely or maintain only minimum generation. Despite the fact that the hurricane was 700 miles from our area and two or more days from projected landfall, Clear Lake Cogeneration -- with a firm contract to sell 396 megawatts to Texas-New Mexico Power Company -- shut down. HL&P had to supply TNP. Clear Lake Cogeneration's decision apparently was based on economics. We were told their thermal requirements customer discontinued steam purchases, and Clear Lake chose not to continue supplying TNP's needs in a conventional generation mode even though they had the capability.

- EXHIBIT 1 -
(PAGE 2 OF 2)

R J SNOKHOUS

Mr. William B. Conway, Jr.
March 30, 1989
Page 2

There was a great deal of complaining by cogenerators in October and November about HL&P's mentioning the shutdowns. The attached copies of correspondence between Dow Chemical and HL&P detail some of that debate. The letters actually involve only one point, however – whether HL&P said all cogenerators planned to shut down. Dow's complaint was that it never intended to shut all the way down, only to 25 or 50 megawatts. We agree Dow never planned to shut down completely. The origin of the controversy was a presentation by L. G. Brackeen to the IPP Market Conference a week after the hurricane threat – his remarks about the hurricane are on pages 8 and 9 of the attached copy of his presentation.

The correspondence proves the point we were making – under adverse circumstances, generators without the statutory obligation to serve can and will fall back on the force majeure clauses in their contracts to cease operations. Their intention to shut down is all the more troublesome when you realize the hurricane never came close to HL&P's service area, and we had weather no more severe than a few showers and a 2.4-foot higher tide.

I have also heard it reported that HL&P asked cogenerators to shut down in anticipation of the hurricane. The chronology of Hurricane Gilbert events attached to L. G.'s November 22 letter shows that we inquired of cogenerators' intentions on September 14 for our own generation scheduling purposes, but never asked any of them to shut down. We would not have done so because we needed the generation. Some of our natural gas suppliers were shutting in wells, reducing our supplies of gas.

HL&P has no particular concerns about cogenerators operating as intended under PURPA. Our concern is whether independent power producers can replace traditional electric suppliers and maintain reliability over the long term at a level that customers, both residential and industrial, expect. This is a significant public policy question which is not being adequately addressed in the current process. There seems to be such a rush to change the electric supply system that important considerations are being overlooked.

I hope this information clarifies our concerns. We would like the opportunity to visit with you again after you have had a chance to review this material. In the meantime if we can answer any questions or provide additional information, please give Howard Pyle or me a call.

Sincerely,

Ray Snokhous

Attachments

- EXHIBIT 2 -
(PAGE 1 OF 5)

The Light company
Houston Lighting & Power

P.O. Box 1700 Houston, Texas 77001 (713) 228-9211

October 12, 1988

Mr. Joe E. Brunt
Business Director
Power/Solid Fuels
DOW Chemical U.S.A.
P.O. Box 3387
Houston, Texas 77253-3387

Dear Joe:

Thank you for your letter of October 4 regarding the remarks which I made concerning cogenerators' performance during the recent hurricane watch. I am enclosing a printed copy of the speech which I used in the IPP conference.

Neither I nor anyone else I have talked to at HL&P said that all cogenerators shut down. The fact is, however, that one cogenerator in our service area did shut down and all three cogenerators supplying HL&P with firm capacity (including DOW) notified us of their intention to declare force majeure should the hurricane move toward the Houston-Galveston area. Along these lines, as I read your letter explaining DOW's hurricane policy, the only factual dispute seems to be whether DOW would shut down 100% or 80% of their electric generation capacity prior to hurricane force winds. If this difference is significant, I apologize for the misstatement. I hope that it does not obscure the fact that HL&P does not plan to declare force majeure on our plants and leave our customers without electricity during any stage of a hurricane. And yes, while we were understandably concerned about the availability of gas for some of our units, especially given the prospect of having to make up the lost cogeneration capacity, our gas storage and oil burning capabilities assured us that our firm customers were not in danger of interruption.

DOW has provided reliable service as called for in the contract and is free to argue that a hurricane is a force majeure event entitling it to suspend electricity deliveries to HL&P's customers. But as you can see from the context of the enclosed remarks, the point was that providing reliable service to electric consumers means being on-line, up and running even

- EXHIBIT 2 -
(PAGE 2 OF 5)

during adverse operating conditions; rather than just designing and building a gas turbine to operate at a 95% capacity factor during normal conditions.. It costs more to design a plant to operate during high winds and high water but our customers have come to expect such service from us and we are committed to providing such service.

Sincerely,

LG Brackeen

L. G. Brackeen
Vice President
Fossil Fuels & Cogeneration

LGB/dn
Enclosure

HURRICANE GILBERT CHRONOLOGY

DATE	TIME	HOUSTON WEATHER	TEMP	TIDE (FT)	GILBERT LOCATION	GILBERT STATUS	COGENERATOR INFORMATION
9/13/88	1300	Partly cloudy	90	+0.6	19.3N - lat 82.8W - long	Declared Force 5	
9/14/88	0800	Clear	73	+0.5	20.4N - lat 86.6 - long	Hit Yucatan	
9/14/88	approx 1000	Clear	84	+0.7	20.7N - lat 87.2W - long	767.5 miles from Galveston	The following responses were received from the cogenerators when they were asked by ECAD what their hurricane plans were: OXY Battleground - will shut down oil production and generation facilities except for one simple cycle GT at minimum load for black start-up capability. OXY-Tidal Road - will shut down and isolate the refinery from the system. One GT will be kept on to satisfy internal load. Clear Lake Cogen - will shut down completely starting at 0500 hours on 9-15-88. They will be completely off-line by noon. Amoco Oil-Texas City - refinery will isolate and keep on enough generation to satisfy internal load only. Amoco-Chocolate Bayou - will shut down completely. Bayou Cogen - may have to keep a generation of on-line to satisfy steam load requirements to their customers. Dow Chemical - will bring their internal load down to minimum and keep approximately 50MW of generation on-line during the storm.
9/14/88	1700	Partly Cloudy	95	+0.7	21.3N - lat 88.8W - long	Entered Gulf Of Mexico	
9/15/88	0800	Clear	75	+1.1	22.0N - lat 91.0W - long	566 miles from Galveston	Clear Lake Cogen shut down 1 GT approx. 70 MW's.
9/15/88	0311	Clear	75	+1.1	22.0N - lat 91.3W - long	558 miles from Galveston	Clear Lake Cogen shut down another gas turbine approx. 100 MW's.
9/15/88	1059	Cloudy	87	+1.9	22.2N - lat 92.3W - long	525 miles from Galveston	Dow Chemical notified HL&P that they would not be changing load or generation until further notice.
9/16/88	0935	Cloudy	78	+2.2	23.0N - lat 96.2W - long	406 miles from Galveston	Dow Chemical notified HL&P that due to projected high tides, Dow may have to shut down; also requested a delay in power scheduling process until 14:00.

- EXHIBIT 2 -
(PAGE 3 OF 5)

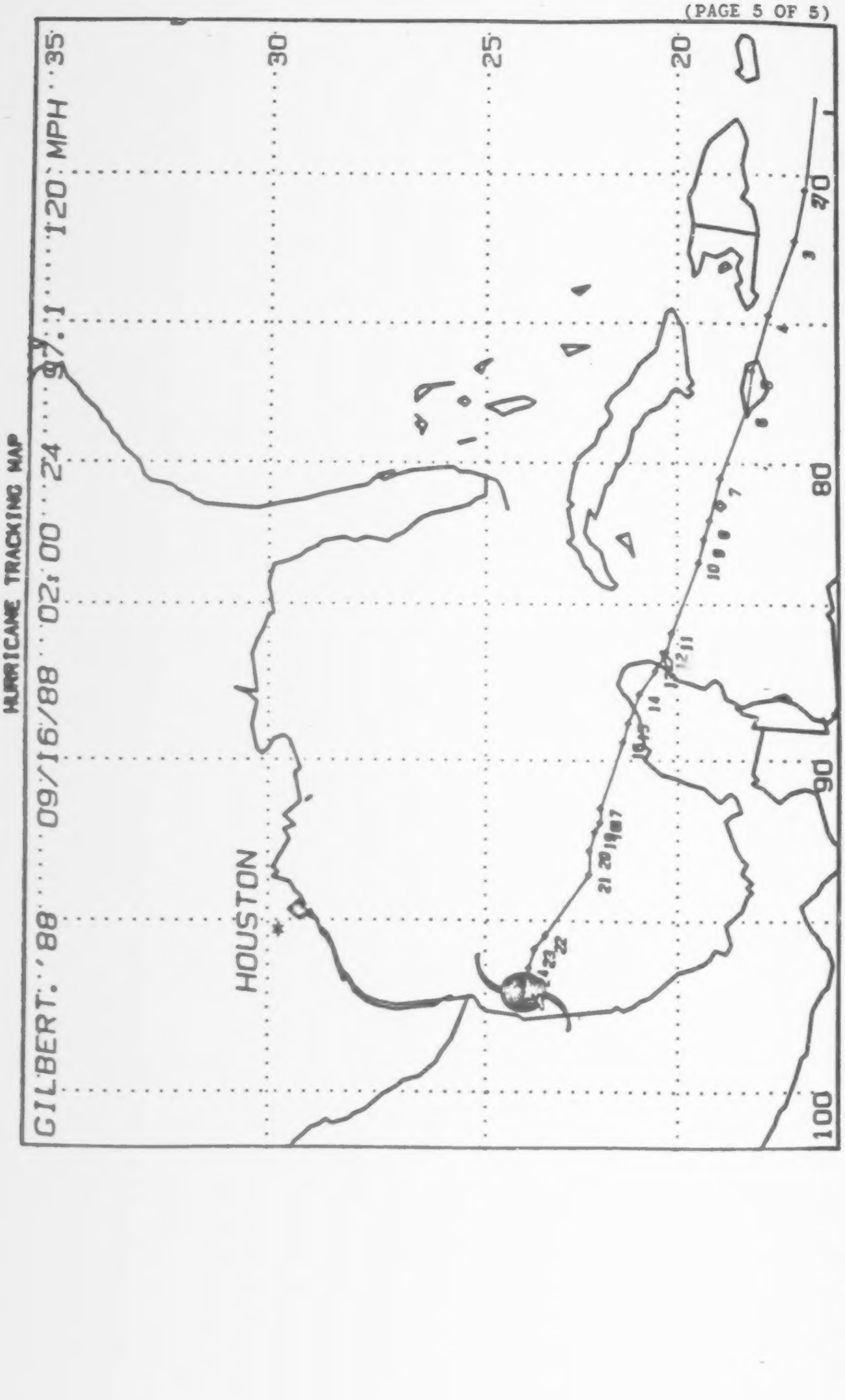
DATE	TIME	HOUSTON WEATHER	TEMP	TIDE (FT)	GILBERT LOCATION	GILBERT STATUS	COGENERATOR INFORMATION
9/16/88	1120	Cloudy	80	+2.3	23.9N - lat 96.4W - long	400 miles from Galveston	Dow Chemical notified HL&P of lower tides than were expected and that they would continue to maintain same load and generation level through the weekend.
9/16/88	1800	Cloudy	86	+2.4	24.2N - lat 97.6W - long	408 miles from Galveston	Clear Lake Cogen started to return to service by adding one gas turbine at a time.
9/17/88	0430	Cloudy	79	+2.3	24.5N - lat 98.0W - long	Hurricane Gilbert made landfall 120 miles south of Brownsville, Tx. 402 miles from Galveston	

PEL:gpl

- EXHIBIT 2 -
(PAGE 4 OF 5)

(PAGE 5 OF 5)

HURRICANE TRACKING MAP


GILBERT '88 09/16/88 02:00 24 97.1 120 MPH
HOUSTON
35
30
25
20
100
90
80
70
23 22
21 20 19 17
16 15 14 13 12 11
10 9 8 7
6
4
3
2

- EXHIBIT 3 -
(PAGE 1 OF 2)

OxyChem.
Robert E. Baker
Director–Energy

January 10, 1991

Mr. L. G. Brackeen
Vice President, Fuel and Energy Management
Houston Lighting & Power Company
P. O. Box 1700
Houston, Texas 77251

Re: Cogeneration Agreement between Occidental Chemical Company (as successor in interest to Diamond Shamrock Chemicals Company) and Houston Lighting & Power Company, Effective January 1, 1984.

Dear Mr. Brackeen:

This is in response to your letter dated November 20, 1990, providing written notice of your intent to terminate the above-referenced Agreement on December 31, 1993, at the end of the initial term.

Occidental Chemical Company's cogeneration facility is a qualifying cogeneration facility within the meaning of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). HL&P's obligation to purchase the capacity and energy made available to it by such a facility is imposed by PURPA, the laws of Texas, including the Public Utility Regulatory Act, and the regulations of the Public Utility Commission of Texas. Under those laws, Occidental is entitled to sell energy and capacity under a long-term contract at rates not to exceed HL&P's full avoided cost based on the particular unit avoided by the QF.

Occidental's facility avoided HL&P's planned Malakoff lignite unit, at a cost lower than the utility's expected cost of constructing and operating that resource. Had the Malakoff unit not been avoided, ratepayers would be required to pay its costs throughout its useful life, which would have begun in the mid-1980's and extended far beyond December 31, 1993. Because Occidental has avoided and is willing and able to continue to avoid the Malakoff unit, Occidental is entitled, in accordance with applicable laws, and hereby offers, to sell energy and capacity to HL&P at Malakoff-based rates, and other terms and conditions contained in the current agreement until 12/31/98, or such later date as may be mutually agreeable.

- EXHIBIT 3 -
(PAGE 2 OF 2)

Occidental Chemical Corporation

Mr. L. G. Brackeen
Houston Lighting & Power Company

January 10, 1991
Page 2

We believe the Agreement, as written, has proved mutually beneficial to HL&P, on behalf of its ratepayers, and Occidental. We look forward to continuing this relationship, and are not abandoning current negotiations with HL&P to find the basis for its continuance.

Very truly yours,

R. E. Baker
Director-Energy

/lh

cc: Earle O'Donnell, Sutherland Asbill
Marianne Carroll, Norton & Blair

- EXHIBIT 4 -
(PAGE 1 OF 2)

The Light company
Houston Lighting & Power
P. O. Box 1700 Houston, Texas 77251 (713) 228-9211

February 5, 1991

Mr. Robert E. Baker
Director - Energy
Occidental Chemical Corporation
Occidental Tower
P.O. Box 809050
Dallas, Texas 75380-9050

Dear Mr. Baker:

In response to your January 10 letter, let me simply indicate that HL&P has absolutely no intention of proceeding along the lines suggested by OxyChem. As we have repeatedly discussed, extension of your current contract would inappropriately impose additional costs on our customers compared to the other options available to us to meet our load in the same time frame. As the attached graph indicates, extension of your current contract through 1998 would cost our customers over $400 million more than other presently available alternatives. Consequently, we have elected to exercise our express contractual right to terminate the contract at the end of its initial term.

Also, we are puzzled by your suggestion that OxyChem may not view the contract, specifically the term provision, as consistent with PURPA and PURA. Certainly, HL&P has always treated the contract as a binding obligation, enforceable in accordance with its terms, and expects nothing less from OxyChem.

To reiterate, HL&P continues to be interested in pursuing contractual arrangements, based on our current supply options, for the possible purchase of power from OxyChem subsequent to the expiration of our existing contract. In fact, we have endeavored to put together alternative purchase arrangements within such a framework that OxyChem might find attractive. At the same time, the notion of extending your current contract is a matter we regard as having been settled by our notice of termination.

Very truly yours,

LG Brackeen

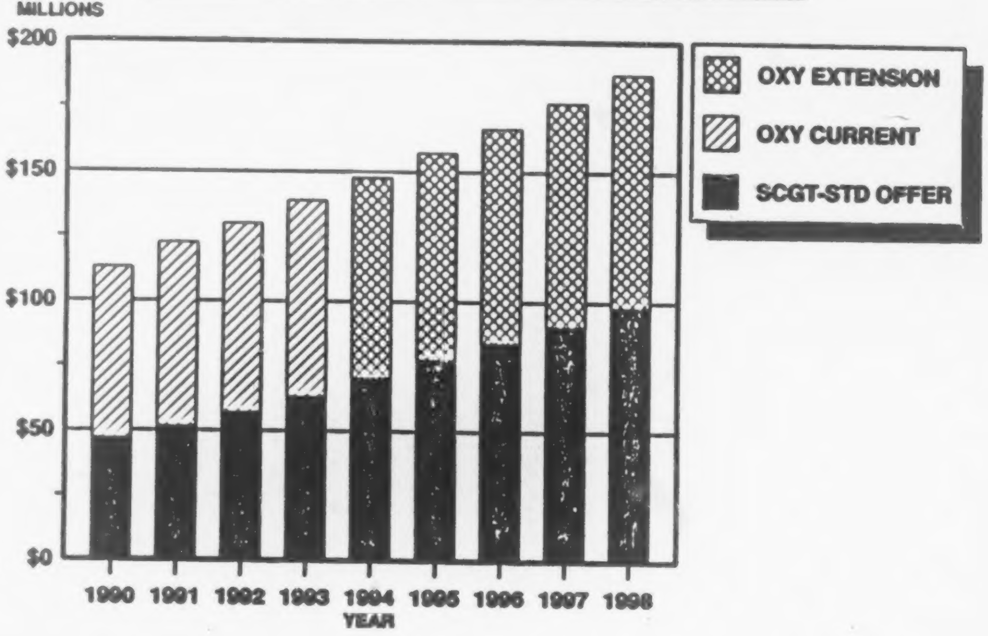
L. G. Brackeen
Vice President
Fuel and Energy Management

Attachment

A Subsidiary of Houston Industries Incorporated

- EXHIBIT 4 -
(PAGE 2 OF 2)

HOUSTON LIGHTING & POWER COMPANY
TOTAL COST COMPARISON CAPACITY & ENERGY



J. BENNETT JOHNSTON, LOUISIANA, CHAIRMAN

DALE BUMPERS, ARKANSAS
WENDELL H. FORD, KENTUCKY
BILL BRADLEY, NEW JERSEY
JEFF BINGAMAN, NEW MEXICO
TIMOTHY E. WIRTH, COLORADO
KENT CONRAD, NORTH DAKOTA
DANIEL K. AKAKA, HAWAII
WYCHE FOWLER, JR., GEORGIA
RICHARD C. SHELBY, ALABAMA
PAUL WELLSTONE, MINNESOTA

MALCOLM WALLOP, WYOMING
MARK O. HATFIELD, OREGON
PETE V. DOMENICI, NEW MEXICO
FRANK H. MURKOWSKI, ALASKA
DON NICKLES, OKLAHOMA
CONRAD BURNS, MONTANA
LARRY E. CRAIG, IDAHO
JOHN SEYMOUR, CALIFORNIA
JAKE GARN, UTAH

BENJAMIN S. COOPER, STAFF DIRECTOR
D. MICHAEL HARVEY, CHIEF COUNSEL
G. ROBERT WALLACE, STAFF DIRECTOR FOR THE MINORITY
GARY G. ELLSWORTH, CHIEF COUNSEL FOR THE MINORITY

United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150

March 20, 1991

The Honorable Joseph I. Giarrusso
City Council President
The Council
City of New Orleans
1300 Perdido Street
Room 2E09
New Orleans, Louisiana 70112

Dear Joe:

Thank you for presenting testimony before the Full Committee on Energy and Natural Resources on S. 341, the National Energy Security Act of 1991, Title XV, concerning reform of the Public Utility Holding Company Act of 1935 (PUHCA).

As a follow-up to the hearing, I have enclosed questions for the printed hearing record. I request that the answers to these questions be provided to the Committee no later than April 5, 1991.

If you have any questions concerning this request, please contact Bill Conway at (202) 224-7149.

Sincerely,

Bennett

J. Bennett Johnston
Chairman

JBJ/wbc

Enclosure

Questions submitted for the Record
Hearing on Title XV of S. 341 and Title IV of S. 570
Senator Dale Bumpers

Please submit the following series of questions to the witnesses representing DOE, FERC, City of New Orleans, Registered Holding Companies, Environmental Action and Consumer Federation of America

A growing number of states have adopted competitive bidding programs for the acquisition of capacity by their native utilities. Such bidding programs are often and appropriately tied to least cost planning or integrated resource planning. More companies will be able to participate in these bidding programs as a result of this legislation.

How does the existence of a multi-state holding company with operating companies in each state affect the ability of the individual state commissions to require that their jurisdictional operating company --

1) engage in integrated resource planning; and/or

2) acquire new capacity through a competitive bidding process?

Assuming that the states each have this authority over their jurisdictional operating company, what authority does each state have to require the holding company to do the same?

Can any existing state or federal regulatory authority compel a multi-state holding company to engage in integrated resource planning or competitive bidding on a regional scale?

Does regional planning and bidding make sense for an integrated multi-state system?

Should we authorize the creation of regional regulatory entities for this purpose?

AND NATURAL RES
1991

The Council
City of New Orleans

JOSEPH I. GIARRUSSO
COUNCILMEMBER AT LARGE

2E09 City Hall
1300 Perdido Street
New Orleans, LA 7011
(504) 565-6335

April 5, 1991

The Honorable J. Bennett Johnston
United States Senator
136 Hart Office Building
Washington, D. C. 20510-1802

Dear Senator Johnston:

As you requested in your letter of March 20, 1991, I am responding to questions submitted by Senator Bumpers regarding my testimony before the Senate Energy and Natural Resources Committee on March 14. Although there are several questions, I would like to address them together, as they all relate to the crux of New Orleans' testimony on the issue of PUHCA amendment -- the need for regional regulatory planning for multi-state utility holding companies registered under PUHCA.

While my response is intended to address the issue of integrated resources planning for all multi-state holding companies, I will focus my comments on the Entergy system. While no two holding company systems are exactly alike, they share many characteristics and thus any observations regarding the Entergy system can be applied to the other registered electric utility multi-state systems. In addition, since customers of the Entergy system have suffered the most as a result of the absence of regulation over holding company generation planning, the New Orleans City Council is well positioned to address the subject.

Generation planning on the Entergy system is conducted by a system-wide Operating Committee, which includes representatives from each operating company. Such planning is undertaken with the goal of meeting the needs of the system as a whole, rather than specific operating companies. While the concept of generation planning on a system-wide basis presents the potential for economies and efficiencies, the current regulatory system is not properly structured to oversee the adequacy of such planning.

State level commissions have traditionally had regulatory focus over utility planning. It is at the state commission level where a regulator can best attempt to ensure that the utility make the most economical capacity decision. In fact, some state commissions require utilities to submit integrated resource plans on a periodic basis. However, the multi-state holding company structure presents significant obstacles for local regulatory involvement in such planning.

If Entergy decides to build a generating plant, the action would affect consumers throughout the system. However, the only state level commission with authority over the decision would be the commission with jurisdiction over the operating company which actually constructs the unit. Even worse, if a wholesale subsidiary were assigned to construct the plant (which occurred with Grand Gulf) no state commission would have authority over the decisions.[1] This lack of regulation over planning decision causes a significant percentage of system consumers to be left unprotected.

In addition to the absence of effective state planning authority, neither the Federal Energy Regulatory Commission ("FERC") nor the Securities and Exchange Commission ("SEC"), the two federal agencies with authority over multi-state holding companies, perform any meaningful oversight of planning. FERC has shown no propensity for reviewing holding company generation planning and, in fact, the Federal Power Act appears not to provide FERC with such authority. The SEC has remained even further removed from the review of such decisions.

1/ Of course, one state would still have sitting authority over the plant. However, such regulation is blatantly inadequate for the performance of integrated planning.

The fact is, that multi-state holding company consumers are being left significantly underprotected. Reality, in the form of system-wide planning, is being met by an anachronistic regulatory structure which forces generation planning to be reviewed on a state-by-state basis.

As was noted in New Orleans' written testimony which was presented to your Committee, the New Orleans City Council has drafted proposed legislation that would authorize the state level regulators of multi-state holding company operating companies to form regional compacts to, among other things, require and oversee the performance of least cost planning. The New Orleans model would prevent holding companies from avoiding adequate regulatory review of their planning decision by playing-off one state against another, or forming wholesale subsidiary corporations. At the same time, such regional regulation answers the alleged concern of the multi-state holding companies that regulation by each state could produce inconsistent results.

If we are to ensure that future utility generation decisions are made wisely so that consumers are served on a least-cost basis and that conservation measures are taken into account as well, we must ensure that state level regulators are adequately equipped to perform the task. The authorization of regional boards to oversee planning on a multi-state holding company system is necessary to achieve this goal. We strongly urge inclusion of the New Orleans' model legislation, which is attached to this letter, in any bill amending PUHCA.

I thank you for the opportunity to respond to Senator Bumpers' questions and hope that this letter will be helpful. As always, New Orleans is prepared to continue this dialogue with you and other members of the Committee.

Sincerely,

Joseph I. Giarrusso

Joseph I. Giarrusso, Chairman
Council Utility Committee

JIG:lgb

cc: All Councilmembers
Bill Conway

CUR 91-96L-4

APR 4 [illegible]

Public Utilities Commission
STATE OF CALIFORNIA
505 VAN NESS AVENUE
SAN FRANCISCO, CALIFORNIA 94102

Patricia Eckert
PRESIDENT

TEL (415) 557-3700
FAX (415) 557-1083

April 3, 1991

[illegible] URCES
[illegible] 1991
[illegible] D.C. 20510

VIA FEDERAL EXPRESS

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and
Natural Resources
United States Senate
Washington, D.C. 20510-6150

Dear Senator Johnston:

Thank you for the opportunity to express my views on S.341, the National Energy Security Act of 1991, Title XV, concerning reform of the Public Utility Holding Company Act of 1935. Attached to this letter are the responses to the two follow-up questions for the printed hearing record.

If I may be of any further assistance, please do not hesitate to contact me or my legal advisor, Ms. Ann Watson at (415)557-2403. I look forward to future opportunities to appear before your committee.

Sincerely,

Patricia Eckert

PATRICIA M. ECKERT
President

Additional Responses of Patricia M. Eckert, President California Public Utilities Commission

1. **"Please provide the Committee with your proposed legislative language to address the federal/state jurisdiction issue." (Senator Malcolm Wallop).**

As my written testimony emphasized, the jurisdictional authority of the States to review wholesale purchases must be clarified and codified by Congress as PUHCA reform occurs. The Pike County doctrine has never been affirmed by the U.S. Supreme Court. If codified, the Pike County doctrine would remove the ambiguity in the law created by the U.S. Supreme Court Mississippi Power and Light decision. I therefore appreciate the opportunity to present proposed legislation to ensure the right of each state commission to review the prudence of the wholesale purchasing practices of each distribution utility subject to its authority.

The following is a preliminary proposal and does not necessarily reflect the views of my fellow commissioners who have not yet taken a formal position on the PUHCA reform proposal embodied in S. 341. My proposal is as follows:

Strike section 15004 of S. 341 and insert the following in lieu thereof:

SEC. 15004. CLARIFICATION AND ENHANCEMENT OF STATE AUTHORITY

General Codification of Pike County Doctrine. -- At the end of section 201 of the Federal Power Act, as amended, add the following:

"Nothing in this Act or the Public Utility Holding Company Act of 1935, as amended, shall preempt or otherwise prohibit a State commission or other retail regulator of an electric utility company from judging the prudence of purchases of wholesale electric energy, and allowing or disallowing in accordance with State law the inclusion of such costs in rates and charges subject to the regulator's jurisdiction, including, but not limited to disallowing recovery of costs determined to be incurred imprudently by a utility operating on an integrated basis under an agreement approved by the Federal Energy Regulatory Commission.

2. In your testimony you noted that California is on the leading edge of developing 'nonprice' bidding concepts which identify the best bidder to serve all consumer interests, not necessarily just the lowest price bidder. Please provide some amplification of California's actions in this respect".

In 1986, the California Public Utilities Commission (Commission) formally addressed the concept of valuing performance, or operational, features to measure the cost-effectiveness of facilities generating electricity. In Re Pacific Gas and Electric Company, 21 CPUC 2d 340 (1986). These features were also referred to as "non-price" attributes. In effect, the Commission decided that more than the price of the fuel used by a facility in generating electricity is to be considered in evaluating its costs as part of a a utility's power system. In that decision, the Commission required the development of a method to value specific performance features on utility systems and the application of these values in the acquisition of new generation facilities through a competitive bidding process. In Re Pacific Gas and Electric Company, 21 CPUC 2d at 376 (1986). This policy was affirmed in 1988. In Re Pacific Gas and Electric Company, 29 CPUC 2d 263, 277-80 (1988).

In a resource planning proceeding currently pending before the Commission, various proposals have been made to account for the environmental impacts of the use of fossil versus non-fossil energy inputs by generating facilities in a bidding process which would simulate a competitive market. A decision on this particular matter is expected by the third quarter of this year. The design of the bidding process and method of valuing environmental impacts should in the near future allow for consideration of additional performance characteristics, such as the ability of a facility to be dispatched readily when and as much as needed. We also expect to value the benefits of fuel diversity among the facilities that comprise the utility's system.

The Commission's efforts are consistent with California law which requires the Commission to "include a value for any costs and benefits to the environment, including air quality", in calculating the cost effectiveness of energy resources. California Public Utilities Code Section 701.1(c), California Public Resources Codes Section 25000.1(c).

LAW OFFICES OF
PAUL, HASTINGS, JANOFSKY & WALKER
A PARTNERSHIP INCLUDING PROFESSIONAL CORPORATIONS
TWELFTH FLOOR
1050 CONNECTICUT AVENUE, N. W
WASHINGTON, D. C. 20036
TELEPHONE (202) 223-9000
TWX 710-822-9062
TELECOPIER (202) 452-8149

COUNSEL
LEE G. PAUL
ROBERT P. HASTINGS
LEONARD S. JANOFSKY
CHARLES M. WALKER

LOS ANGELES OFFICE
555 SOUTH FLOWER STREET
LOS ANGELES, CALIFORNIA 90071
TELEPHONE (213) 683-6000

ORANGE COUNTY OFFICE
695 TOWN CENTER DRIVE
COSTA MESA, CALIFORNIA 92626
TELEPHONE (714) 641-1100

WEST LOS ANGELES OFFICE
1299 OCEAN AVENUE
SANTA MONICA, CALIFORNIA 90401
TELEPHONE (213) 451-1200

ATLANTA OFFICE
GEORGIA-PACIFIC CENTER
133 PEACHTREE STREET, N. E.
ATLANTA, GEORGIA 30303
TELEPHONE (404) 588-9900

CONNECTICUT OFFICE
1055 WASHINGTON BOULEVARD
STAMFORD, CONNECTICUT 06901
TELEPHONE (203) 961-7400

NEW YORK OFFICE
9 WEST 57TH STREET
NEW YORK, NEW YORK 10019
TELEPHONE (212) 838-6100

TOKYO OFFICE
TORANOMON OHTORI BUILDING
4-3, TORANOMON 1-CHOME
MINATO-KU, TOKYO 105
TELEPHONE (03) 507-0730

April 5, 1991

WRITER'S DIRECT DIAL NUMBER
202457-9455

OUR FILE NO

VIA MESSENGER

The Honorable J. Bennett Johnston
Chairman
Senate Committee on Energy
 and Natural Resources
364 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Mr. Chairman:

Thank you for permitting me to testify before the Full Committee on Energy and Natural Resources on S.341, The National Energy Security Act of 1991, Title XV, concerning reform of the Public Utility Holding Company Act of 1935.

Enclosed are my responses to the questions for the printed hearing record. If you have any additional questions or if I can be of further assistance, please do not hesitate to contact me.

Very truly yours,

Charles A. Patrizia
of PAUL, HASTINGS, JANOFSKY & WALKER

Encl

cc: w/encl
The Honorable Dale Bumpers
The Honorable Malcolm Wallop

RESPONSES BY CHARLES A. PATRIZIA TO QUESTIONS SUBMITTED FOR THE RECORD HEARING ON TITLE XV OF S. 341 AND TITLE IV OF S. 570

Question:

A growing number of states have adopted competitive bidding programs for the acquisition of capacity by their native utilities. Such bidding programs are often and appropriately tied to least cost planning or integrated resource planning. More companies will be able to participate in these bidding programs as a result of this legislation.

How does the existence of a multi-state holding company with operating companies in each state affect the ability of the individual state commissions to require that their jurisdictional operating company --

1) engage in integrated resource planning; and/or

2) acquire new capacity through a competitive bidding process?

Assuming that the states each have this authority over their jurisdictional operating company, what authority does each state have to require the holding company to do the same?

Answer:

In considering the proper scope of state regulatory authority over integrated resource planning in the context of multi-state holding companies, any analysis must start from the fact that the registered holding companies are governed by the Public Utility Holding Company Act of 1935 (the "'35 Act" or "PUHCA"). The '35 Act requires multi-state holding companies operations to operate integrated utility systems.

The nine registered holding companies and their operating companies plan and operate their systems on the basis of pooled reserves, coordinated construction of generation units and coordinated scheduled maintenance. They centrally dispatch the generating facilities within the system on an economic basis, that is, on a basis that assures that the next load is served by the next lowest cost available generating resource, no matter where on the system the load or the resource is located. Thus, the registered holding companies and their affiliated operating companies already engage in system wide "least cost planning" and operation. This assures that the registered companies provide numerous benefits to investors, consumers, the general public and the states they serve.

Continued achievement of these system-wide benefits rests on assuring that individual state commissions cannot compel actions not in accord with integrated system operations or which impose costs on other affiliates. See AEP Generating Co. and Kentucky Power Co., 38 FERC ¶ 61,243, modified, 39 FERC ¶ 61,158 (1987)(state commission may not require jurisdictional utility to "lean on" lower cost system power to the detriment of the other affiliated operating companies). Thus, federal jurisdiction must be preserved to prevent a state from imposing a planning process or even a bidding program which would not take into account system needs or which would contradict federally approved allocations.

The maintenance of this "bright line" between federal and state authority is particularly important in multi-state holding companies. In a holding company system, the operating companies coordinate planning and integrate operation in order to maximize the benefits to consumers. For the benefits of such integrated operation to be fully realized, states must not be permitted to subject such systems to conflicting parochial directives, which would seek to shift costs from one state or set of ratepayers to others. For example, a state commission may not require that an operating company of a holding company subsidize a qualifying facility by purchasing electricity at a price greater than the utility's avoided costs if the other affiliate companies would have to pay part of the subsidy. See Middle South Services, Inc., 24 FERC ¶ 63,119, 65,216-17 (1983).

The ultimate determination of system resource allocation must rest at the federal level. This principle was recently reaffirmed by the Supreme Court in Mississippi Power and Light Co. v. Mississippi ex. rel. Moore, 487 U.S. 354 (1988). Requiring a multi-state holding company to separately plan at the operating utility level, without integration at the system level, or to obtain the approval for an integrated resource plan from each state in which it operates, would subject the registered company to potentially conflicting guidance and would violate PUHCA's integration objectives.

Subject to the constraints set forth above, some state commissions may (and some actively do) require operating companies within their jurisdiction to engage in and report on the coordinated planning process as it affects retail operating companies, and states may require each retail operating company to use a competitive bidding process or to explore various conservation or load management activities. State plenary control over financing, corporate organization, and siting also provides states with a mechanism over prior approval of projects that will be undertaken by their jurisdictional utilities. In some states a need for power, consistent with least cost planning principles, must be demonstrated before a project can be approved for siting or financing.

Any authority by the states to require resource planning, however, must be consistent with system integration and planning, and cannot overcome or replace federal authority over ultimate allocation and wholesale rates. Thus, states may, for example, require an operating company to consider bidding programs as part of a plan to supply required capacity, but that requirement cannot be implemented in such a way as to impose additional costs on other system companies or to prevent other appropriate system planning efforts.

Question:

Can any existing state or federal regulatory authority compel a multi-state holding company to engage in integrated resource planning or competitive bidding on a regional scale?

Answer:

Under the '35 Act, the properties and business of the registered holding companies are "confined to those necessary or appropriate to the operations of an integrated public utility system." 15 U.S.C. § 79k(a). Under the mandate of the '35 Act, the registered companies already engage in "regional resource planning" as part of their coordinated planning and integrated operations. There is no specific SEC requirement or authority to engage in regional competitive bidding. Of course, the registered companies have an economic incentive to maximize the benefits of operating on an integrated basis through increased efficiencies and resource planning.

FERC already requires its jurisdictional entities, which would include holding company generation subsidiaries and operating companies selling at wholesale, to pursue a form of least cost planning if the utility elects to include Construction Work in Progress ("CWIP") in its rate base. Under FERC's CWIP regulations, a utility may only include CWIP on the basis of forward looking allocation ratios, which reflect the anticipated average annual use of the wholesale customers using the new project over its estimated life. 18 C.F.R. § 35.26. Placing this constraint on CWIP allocation permits utilities to send price signals more closely reflecting their future costs and forces utilities to pursue least cost strategies to meet their customers electric power needs.

Because state commissions lack regional or federal authority, an individual state commission does not (and should not) have the authority to compel a multi-state holding company to engage in a specific integrated resource plan or competitive bidding on a regional scale. To permit individual state commissions to exercise such authority would subject multi-state holding companies to potentially conflicting directions from the individual states and is counter to the goal of integrated resource planning. In any event, there is no need to grant such authority to states, because state jurisdiction properly focuses on the operations and planning of the jurisdictional entity within that state, and as described above, states already have sufficient authority over the elements of the coordinated plan that affect the jurisdictional entity.

Question:

Does regional planning and bidding make sense for an integrated multi-state system?

Should we authorize the creation of regional regulatory entities for this purpose?

Answer:

As noted in my testimony and discussed above, as required by federal statute, the registered holding companies already engage in "regional" planning which is essential to integrated operation. A requirement of bidding programs is not essential to integrated planning, although utilities that need capacity may consider a bidding program. At present, by functioning on an integrated basis, including staggering construction, pooling resources to take advantage of maintenance and load differences, and centrally dispatching the generating facilities within the system, the registered companies achieve many of the benefits of integrated resource planning. Thus, as Congress determined 55 years ago, a multi-state company's integrated operation "makes sense" on a regional basis.

As discussed above, under the '35 Act, the registered companies are required to operate on an integrated basis. They already have significant economic incentive to plan on a regional basis and maximize the benefits of integrated operation. To the extent that further regulatory oversight is necessary, the proper locus is a neutral federal administrative forum. An extension of the state's role as envisioned by proposals for regional regulatory boards ("RRB") is unnecessary and unworkable. As discussed in greater detail in my written testimony, there are a number of practical problems with utilizing a regional regulatory approach for multi-state companies.

First, each multi-state holding company would be regulated by a separate RRB. Several states, however, are served by two or more holding companies. Thus, some states might have representatives on two RRBs and potential conflicts between the goals of the different RRBs would not be conducive to certainty in the planning process or establishing an integrated resource plan for a specific region. Second, multiple RRBs would hinder the registered companies' ability to continue to plan and operate in an integrated manner, as PUHCA requires. By subjecting the integrated planning of registered companies to review by a cumbersome ad hoc body, an additional layer of bureaucratic scrutiny and regulatory uncertainty is imposed on the efficient operation of the registered systems. Third, if an RRB fails to agree on an integrated resource plan, there must be an entity empowered to make such a decision. Presumably this will be FERC or another neutral federal administrative forum, thus demonstrating the essential federal interest. If Congress elects to make such a policy choice and increase regulatory oversight with respect to least cost planning issues, FERC is better suited than an RRB to resolve these issues in the first instance for a multi-state holding company. FERC is an established neutral administrative forum, a uniform body of case law already exists, FERC procedures are well established and the interests of the individual states could be presented in the proceeding before FERC.

April 5, 1991

Appendix II—Additional Material Submitted for the Record

CMS ENERGY

William T. McCormick, Jr.
CHAIRMAN & CEO

April 5, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
364 Dirksen Senate Office Building
Washington, DC 20510-8150

Dear Senator Johnston:

I am writing in response to testimony submitted by the Michigan Public Service Commission (MPSC) in connection with S. 341, TITLE XV, which reforms the Public Utility Holding Company Act.

In the MPSC's testimony there are a number of concerns expressed about PUHCA reform that are based on alleged abuses by my Company, CMS Energy Corporation (CMS). Let me say that while some state public utility commissions (PUCs), including the MPSC, are concerned about their role in an industry in which there is greater wholesale competition, I do not believe that our Company has been guilty of any of the abuses suggested in the MPSC's testimony or that such alleged abuses will result from S. 341. In fact, the "documented" abuses cited by the MPSC are simply assertions made by various parties or the MPSC itself and most of those disputed matters are pending before the Michigan Courts.

Nevertheless, for the record, I believe it is important to set the facts straight and I would ask that my letter be entered after the MPSC's testimony in the formal Committee record.

Assertion 1: Lack of arms-length bargaining in an affiliate power contract with Consumers Power Company.

This assertion is totally inaccurate since the rate in the power contract between Consumers Power Company and the Midland Cogeneration Venture (MCV) was set at the precise

PURPA avoided cost established by the MPSC itself for cogeneration projects approved by the MPSC three months prior to the MCV contract execution. In other words, there was no bargaining between the utility and its affiliate on the price of the power. The price in the contract was established at the avoided cost set by the MPSC itself. The dispute referred to by the MPSC, which is now at the Michigan Court of Appeals, centers on the MPSC's authority to retroactively change the avoided cost after the MCV contract was executed.

More generally, any problem of lack of arms-length bargaining under PUHCA reform would be highly unlikely since a rate for a wholesale power generator must be approved by the Federal Energy Regulatory Commission (FERC) as just and reasonable. If, on the other hand, the project were a PURPA project, the rate for an affiliate or non-affiliate must be at or below the avoided cost set by the State PUC.

Assertion 2: Favoritism with respect to an affiliate's capacity and over-subscription of capacity from an affiliate.

With respect to the over-capacity issue, in its own order, the MPSC determined that Consumers Power Company needed 1290 MW of additional capacity to maintain a prudent reserve margin of 23%. The issue with respect to the MCV contract which totalled 1240 MW was never the total capacity needed by the utility, but rather whether other smaller cogenerators, whose projects were non-existent at the time the MCV contract was submitted to the MPSC for approval, should be arbitrarily allocated some of the MCV contract capacity. The MPSC ordered Consumers Power Company to do so, despite the fact that it was illegal to compel Consumers Power to sign such contracts, as decided this month by the Michigan Court of Appeals.

More generally, the potential problem of favoritism of an affiliate's power cannot occur as a result of PUHCA reform since the exempt wholesale generator must receive a FERC-approved rate which would not be given to an affiliate if a non-affiliated power supplier was better for the customer.

Assertion 3: Corporate restructurings which would be encouraged by PUHCA reform are harmful to a regulated utility.

There is nothing either wrong or illegal about incorporating a utility into a holding company structure. In fact, the MPSC endorses, in its own testimony (in point #1 on Page 4), the view that all non-utility activities of holding companies be segregated from the utility's activities or through separate corporate subsidiaries. This is precisely what CMS Energy has done. Furthermore, CMS has also followed point #2 on Page 5 of the MPSC's recommendations in that there are few contracts between our utility and non-utility subsidiaries and all such transactions have been subject to MPSC audit. The disagreement with the MPSC has been over whether they should have access broadly to the books and records of all non-utility subsidiaries and the parent company on matters not involving transactions with the utility. Moreover, consistent with the MPSC's recommendation #3 on Page 5 of their testimony, CMS Energy has not used any utility management, funds, or credit for non-utility purposes. The MCV assets in dispute were never utility assets and never subject to State PUC jurisdiction. In short, we strongly agree with the MPSC that there should be no cross-subsidies between utility and non-utility affiliates.

Assertion 4: Holding company structures and transactions among affiliates will result in extensive lengthening of regulatory proceedings and greatly increased resources needed by PUCs.

Michigan's experience of regulatory delay has not been the result of problems caused by holding companies. Sadly, Michigan's track record for lengthy and litigious utility regulation is legendary (i.e., having the longest average rate cases of any state in the U.S.) and has existed at least a decade prior to the formation of CMS Energy in 1987 or even the other utility holding companies in Michigan. The problem in Michigan has largely been the delay tactics of the State's Attorney General and other intervenors. In the case of the MCV rate proceeding, it was the MPSC itself which first delayed the power contract approval and then opened the proceeding up and requested other interested parties (of which there were in excess of 50) to submit competing power contracts to the MCV and to enter testimony. The serious regulatory delay problems in Michigan have generally not been a problem in other states and have certainly not been the result of holding company structures. Thus, PUHCA reform should not impact this issue.

Finally, let me say that CMS Energy, as the lowest-cost major supplier of electricity in Michigan, vigorously supports PUHCA reform and S. 341, TITLE XV, and believes its enactment will significantly benefit electric customers throughout the U.S. as a result of the greater number of power supply options available to utilities and the more competitive power market that will develop.

Sincerely,

Bill McCormick

William T. McCormick, Jr.
WTM/lrt

CC: ✓William Conway
Michigan Congressional Delegation
Michigan Public Service Commission

Rec'd 3/29

1991
WASHINGTON, D.C. 20510

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION
ALBANY 12223

PETER A. BRADFORD
CHAIRMAN

THREE EMPIRE STATE PLAZA
(518) 474-2530

March 27, 1991

J. Bennett Johnston
United States Senator
Chairman, Committee on Energy
  and Natural Resources
Washington, D.C. 20510

Re: Proposals to Amend the Public Utility Holding Company Act of 1935

Dear Senator Johnston:

The Natural Energy Security Act (S. 341) and the Bush Administration's National Energy Strategy Act both contain amendments to the Public Utility Holding Company Act of 1935 (PUHCA) that are intended to foster development of independent power production throughout the country. New York electric utilities have initiated capacity bidding programs to take advantage of utility and non-utility sources alike in meeting the State's future electric needs, and an open and competitive generation marketplace is critical to the success of those efforts. Any amendments to exempt electric wholesale generators from PUHCA, however, need to preserve necessary ratepayer protections against cross-subsidization, utility self-dealing with exempt producers and imprudent power supply planning processes. Moreover, PUHCA amendments should only be considered a part of a comprehensive package that gives states jurisdiction over all intrastate electric transactions.

As explained in the attached New York State position paper, the circumstances that have provoked the PUHCA debate are the consequence of state and federal efforts to protect ratepayers and to promote competition among all power suppliers and energy efficiency projects to meet future electric needs. Realigning federal and state authority over electric energy is essential for state regulators to accomplish these tasks, would eliminate a considerable number of local power matters that distract the Federal Energy Regulatory Commission from national matters, and remove much of the cause for friction between state and federal regulators.

I ask that this letter and the attached position paper be incorporated into the record of the PUHCA hearing held before the Energy and Natural Resources Committee on March 14, 1991. Thank you for considering these views on this important matter.

Sincerely,

Peter Bradford

pp/391-90

Position Paper of the State of New York
Concerning
Amendments to the Public Utility Holding Company Act of 1935

National Energy Strategy Act, Title IV
National Energy Security Act, Title XV (S. 341)

* * * *

Overview

Both comprehensive energy legislative packages before Congress contain proposals to exempt independent (i.e., not regulated utility) power producers selling electric energy at wholesale from the constraints and regulatory burdens of the Public Utility Holding Company Act (PUHCA).

Revisions needed to the federal system of power regulation to accommodate changes in the electric industry should be made systematically. They should be guided by the underlying principle that the states are best able to regulate the economic and environmental impacts of electric generation and transmission within their own borders. The federal government should regulate matters that are interstate in character or impact and should, of course, protect the national security aspects of energy supply. All aspects of intrastate utility operations -- generation, transmission and distribution -- and demand side management efforts should be subject to state regulatory oversight.

Legislative changes that open the competitive power market for utility-affiliated and unaffiliated "independent power producers" in ways that erode the ability of states to protect consumers and the environment are unacceptable. Before reducing the PUHCA's protections against consumer abuse, Congress should ensure that state and federal regulatory lines of authority are properly aligned to offer comparable or superior protection.

Background

Electric utilities traditionally built the power plants needed to meet their customers' electric needs. The need for new capacity, the siting of generating units and necessary transmission facilities, fuel type, environmental permits and rates were, and continue to be, matters indisputably for states to address. The reasonable cost of building and operating such plants are charged to consumers in retail rates.

State agencies set the rate for sales from utilities to customers but rates for all wholesale sales of electricity, no matter how small or how clearly intrastate they may be, are set by the federal government.

Three developments in the 1980's altered this traditional environment. First, the Public Utilities Regulatory Policies Act of 1978 (PURPA) policies encouraging non-utility alternative power production far exceeded expectations. PURPA's incentives gave birth to a new industry of private power producers seeking to make a profit selling power to utilities. Utilities in the state of New York alone have entered into contracts to buy more than 7,000 megawatts[1] from PURPA "qualifying facilities" ("QFs").

Second, dramatic cost overruns in nuclear and some other construction called historic laissez-faire regulation into question. State reviews uncovered major instances of unwise planning and construction. The Federal Energy Regulatory Commission (FERC) lacked the resources and the will to conduct serious reviews of power plant costs under its jurisdiction. Some utilities have been inclined to buy additional generating capacity at wholesale from other utilities, unregulated utility affiliates or "non-utility" producers, thereby securing FERC jurisdiction over the transaction, rather than to build new facilities. This circumstance has called into question the roles of state and federal regulators and caused a considerable amount of litigation of federalism questions and preemption doctrine. Recent Supreme Court decisions suggest that a "buy rather than build" approach may indeed permit utilities to avoid state scrutiny over the costs of such wholesale transactions, even when the transactions are entirely intrastate in nature.

Third, New York has been at the forefront of state, and more recently, federal[2] efforts to promote fully integrated power supply planning by utilities. This means that utility planners examine the full array of resource options available to them to meet future electric needs. Conservation and load management (collectively referred to as demand side management or "DSM") are one critical element of a least cost utility plan Another involves taking advantage of the competitive forces in the power generation sector through capacity bidding. New York's seven investor owned utilities are conducting "all source" auctions that consider all available supply and demand resources. The objective of the auctions is to ascertain the combination of options -- new utility generation or transmission construction, life extension of existing units, capacity purchases from other utilities or non-utilities, and DSM -- that will best provide for safe, reliable and reasonably priced electric energy in the State.

---

[1] Peak power demand in New York State in 1990 was approximately 27,000 MW.

[2] The Clean Air Act Amendments of 1990 require state regulators to approve utility least cost power plans as a pre-condition to eligibility for energy conservation and renewable energy bonus emission allowances (Clean Air Act §404(f)(2)(B)).

PUHCA requires utility holding companies to operate as a single integrated system, and effectively confines utility operations to the state in which a utility is organized and contiguous states. For this reason, a California utility historically could not build power plants in New York State without running afoul of PUHCA.

PURPA created an exemption from PUHCA for many "qualifying facilities"[1] and utilities have used this exemption through joint venture arrangements permitted by PURPA (a utility may own up to a 50% interest in a QF).[2] Many power producers, both utility and non-utility, however, find it difficult to meet the technical requirements of PURPA and compete successfully in capacity auctions. Consequently, the PUHCA exemption provided by PURPA often has little value. Also, many utilities believe they could apply their expertise and resources to build power plants throughout the country, if they were not confined geographically by PUHCA, more economically than the local utility could build capacity itself.

---

[1] 18 C.F.R. 292.602(b).

[2] 18 C.F.R. 292.206.

State regulators generally welcome the most proficient, lowest cost power producers, regardless of ownership. They prefer a system of regulation that maximizes the competitiveness of the generation market because it furthers state least cost supply goals, provided that adequate protection of consumer interests is retained.

The PUHCA Proposals

In 1989, Senator Johnston proposed an amendment to PUHCA that would create a category of "exempt wholesale generators" (EWG) that would not be subject to PUHCA requirements. In essence, virtually any non-rate based generating plant would be exempt from PUHCA, regardless of its location or whether it was owned by a utility, a registered utility holding company, an industrial firm or other non-utility power developers. The bill failed to protect against utility self-dealing with EWG affiliates or utility cross-subsidization of EWG projects with consumer-provided funds. More important, by promoting IPP development without addressing the roles of state and federal regulators, the amendment promoted forum shopping that would allow utilities to overcharge consumers by avoiding state regulation as a result of their taking refuge in the overburdened and arguably "friendlier" federal wholesale jurisdiction.

The National Energy Security Act (S.341; Title XV), submitted by Senators Johnston and Wallop this year, reintroduces the EWG exemption from PUHCA with one notable addition. Title XV provides that a utility may elect not to purchase electric energy from EWGs by filing an irrevocable declaration of such intent with the FERC. The declaration may be effective for as long as 10 years, and, while it is in effect, the utility and its affiliates may not own or acquire an interest in an EWG. State regulators are expressly prohibited from imposing any penalty of any kind upon a utility electing to avoid EWG purchases.

Because it condones a utility decision to disregard available non-utility resources, no matter how inexpensive they may be, this "opt out" provision is completely contrary to prudent utility planning and would seriously undermine efforts to develop a competitive generation market through capacity bidding. Indeed, it undermines the entire reason for amending PUHCA in the first place. Just as the EWG exemption is intended to promote IPP development, the "opt out" provision would allow utilities to ignore the IPP market. By allowing such an "opt out" declaration to be made at any time and for any (or no) reason, and by preempting state regulatory action, the bill creates a chilling environment where bidding and other IPP construction would suffer greatly from uncertainty alone. Even if the remaining deficiencies in the bill were rectified, legislation containing the "opt out" provision is unacceptable.

The Administration's National Energy Strategy Act also contains an EWG amendment to PUHCA. The bill makes an effort to address basic consumer safeguards by requiring exempt utility holding companies to develop "appropriate" mechanisms to allocate costs between EWGs and any parent or affiliated utility providing retail service, and by prohibiting EWG sales to an affiliated utility without the prior approval of each affected state regulatory commission.

It is not clear whether the bill intends federal regulators (SEC or FERC) or state authorities to be responsible for reviewing and approving the cost allocation mechanisms. Also, accounting conventions alone may be inadequate to prevent those abuses. Under current technology, electric energy must be delivered to purchasers at the time it is produced. Consequently, effective regulatory oversight of the potential for cross-subsidies, self-dealing and other abuses may be exceedingly difficult or impossible unless utility policies concerning the rendition of transmission services are subject to appropriate state and federal control.

The Administration's bill requires FERC to determine whether prices charged by EWGs are "just and reasonable" under the Federal Power Act and that no undue preference arises from an affiliated relationship between an EWG and the utility purchasing power from it. A State commission may decide the prudence of wholesale power costs by an electric utility buying from an EWG (and disallow imprudent costs) unless the buyer has no alternative to accepting (1) the amount of power or (2) the costs allocated to it by FERC in setting a wholesale rate based on an allocation of power or costs among:

1. companies of a registered holding company, or
2. companies that operate on an integrated basis under a FERC approved agreement.

This provision is intended to address state concerns that any EWG amendment to PUHCA must expressly authorize state regulators to address in retail rate decisions the prudence of a utility's wholesale power procurement choices compared to other available choices.[1] It has been drafted, however, to preempt such state inquiry where FERC has mandated an allocation of power or costs in setting wholesale rates. As drafted it certainly seems designed to prevent a recurrence of the multiple levels of administrative and court litigation associated with the Grand Gulf nuclear plant built by the Middle South/Entergy system. It might also be read, however, to expressly preempt state action in any wholesale transaction involving members of a power pool agreement, in effect negating Pike County altogether. The language of the bill needs to be modified to describe unambiguously the power reserved to the states.

---

[1] This authority is generally referred to as the Pike County doctrine. Pike County Light & Power Co. v. Pennsylvania P.U.C., 77 Pa. Commw. 268, 465 A.2d 735 (1983).

Running through this field is the unnecessary complexity created by federal jurisdiction over intrastate wholesale sales of electricity. States that routinely regulate the economics of 1000 megawatt utility-owned power plants are barred from regulating 10 megawatt wholesale sales of most sorts. Instead, these transactions are inefficiently and ineffectively regulated in Washington. This circumstance is an anachronism. No one would choose it as a sensible allocation of responsibility today if it were not already in place. No serious effort at utility regulatory reform can go forward without adopting the inter-intrastate division of responsibility between the state and federal jurisdictions that is already in place in the telecommunications field.

NSP

Northern States Power Company

655 Fifteenth St. N.W., Suite 300
Washington, DC 20005
Telephone (202) 638-4051

Gay H. Friedmann
Director Federal Governmental Affairs

March 28, 1991

The Honorable J. Bennett Johnston
Chairman, Senate Energy Committee
364 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Mr. Chairman:

I am enclosing testimony on behalf of Northern States Power Company supporting reform of the Public Utility Holding Company Act subsequent to the Committee's hearing on this issue.

I would appreciate your submitting this testimony for the record.

Sincerely,

Gay H. Friedmann

Testimony of Northern States Power Company
in Support of
Reform of the Public Utilities Holding Company Act
March 14, 1991

Mr. Chairman and Members of the Committee, Northern States Power Company (NSP) appreciates the opportunity to provide you with it view on potential amendment of the Public Utility Holding Company Act of 1935. We commend you for holding hearings on this issue of great importance to the electric power industry and our nation's electricity consumers.

NSP is an integrated electric and gas utility serving 1.66 million customers in Minnesota, Wisconsin, North and South Dakota and the upper peninsula of Michigan. NSP's electric rates rank among the lowest in the country, and our power plants have among the lowest emissions of potential acid rain-causing pollutants of any power plants in the nation. We are also aggressively pursuing demand-side management and conservation. These efforts have already resulted in a reduction of nearly 500 megawatts of peak electric demand, and we are committed to achieving a total savings of 1,000 megawatts by 1995.

As these achievements suggest, NSP believes that certain changes in the electric industry are beneficial. One such change that would be advantageous to consumers and the industry alike is amendment of the Public Utilities Holding Company Act (PUHCA). We thank you for this opportunity to express our views on this important topic, and begin our testimony with a brief background of PUHCA.

THE BIRTH OF PUHCA AND EARLY STRUCTURE OF THE INDUSTRY

The Public Utility Holding Company Act was passed in 1935 to protect both investors and consumers from abusive holding company structures. To ensure that utilities divested themselves of unproductive assets, the Act essentially limited utilities to single service territories and single lines of business. The Act has been the major influence in shaping an industry structure of vertically integrated utilities that generate, transmit and distribute electric power to franchised customers.

This industry structure worked extremely well from 1935 until the first energy crisis in the early 1970s. Until the early 1970s, economic growth was steady. Utilities were able to add base-load power plants and distribute power to customers at declining rates, thanks to economies of scale in power generation. Utilities built plants to meet the needs of their customers and earned a fair rate of return on their investment for shareholders. But the first energy crisis changed the picture. Cost of capital sky-rocketed, inflation increased to double digit levels, fuel costs more than doubled, and the nation's economy fell into severe recession. Because of this, several utilities were left with expensive construction programs during a period of shrinking demand for their output. As a result, state regulators frequently disallowed utility requests to put plant costs into the rate base causing many utilities to become extremely risk averse.

THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

In 1978, Congress passed the Public Utility Regulatory Policies Act (PURPA). PURPA changed the utility industry structure by creating a favored class of power suppliers called Qualifying Facilities (QFs). QFs are power producers (those plants utilizing biomass, waste, renewable resources or geothermal resources as the primary energy source) and cogenerators (those producing steam and electric power) that meet certain size, fuel type, and other criteria. The law required utilities to purchase the output of these entities at the utilities' avoided cost of generating power. Most importantly, QFs were exempt from PUHCA's complex regulatory structure.

PURPA has taught the nation two major lessons. First, entities other than public utilities are willing and able to supply power at wholesale. Second, we have learned that electric generation is no longer a natural monopoly; competition is possible. Because of PURPA, non-utility generators have supplied a significant percentage of the nation's generating capacity in recent years and are forecast to supply even more capacity in the future.

THE INEFFICIENCIES CAUSED BY PURPA

Several problems have been associated with PURPA. First, some utilities have been forced to procure power from QFs, whether or not the power was required. Secondly, the price a utility pays a QF is based on the utility's avoided cost, rather than on the QF's actual cost or on the market price, both of which can be lower than utility avoided cost. Finally, QFs structure their projects to conform to PURPA to be exempt from PUHCA. This requires cogenerators to locate a steam host and then construct a plant to generate steam as well as electricity, often at the cost of millions of dollars.

As a result, the nation is relying on a favored class of generator to assist in achieving power supply requirements. These generators can force utilities to buy unneeded electricity at higher-than-market prices. NSP believes that it is time to expand the options available to utilities to meet their power supply requirements. PURPA and PUHCA, as currently constituted, inhibit the efficient development of non-utility power projects and ultimately raise the consumer price of electricity.

REMOVING INEFFICIENCIES BY AMENDING PUHCA

NSP supports amending PUHCA in such a way as to facilitate entry into wholesale electric power markets by Independent Power Producers (IPPs), also referred to as Electric Wholesale Generators (EWGs). IPPs, or EWGs, are power suppliers which do not meet the fuel, scale, ownership or technology requirements that PURPA imposes on QFs. Unfortunately, EWGs are stifled by PUHCA. Under current PUHCA regulation, IPPs owning and operating 10 percent of a plant, and 5 percent of a second plant, are considered public utilities, and, as such, are subject to the Act's complex regulatory structure. Additionally, the Act requires utilities to limit their business activities to contiguous states. This is a disincentive to the development of EWG projects. At a time when some areas of the nation require significant new generating capacity to meet the demands of a growing economy, NSP believes that the public policy goal should be to expand options to encourage market-based pricing for electricity.

Our own company serves as an example of how PUHCA reform could expand ways to meet the need for electric capacity by easing the requirements for EWGs. NSP is a holding company, exempt from some of PUHCA's regulatory requirements because our operations are predominantly in contiguous states. (There are four other exemptions from the Act.) NSP has established an unregulated affiliate, NRG Energy, Inc. (NRG), that is attempting to develop independent power generation projects. But to maintain our PUHCA exemption, current law requires us to structure NRG's projects in a convoluted fashion. Although we will move ahead with NRG absent changes to PUHCA, the process is extremely inefficient. Lawyers and other conformance specialists continue to reap large fees helping EWGs and utilities like NSP and NRG to meet PUHCA structural requirements. Such expenses add to the price of electricity.

MAXIMIZING ENERGY OPTIONS

We believe that changes to the Holding Company Act would be beneficial to the nation. Changes would maximize energy options for the nation's utilities and consumers, enabling utilities to purchase power from the suppliers that most closely meet the utilities' fuel requirements, budgets, and reliability needs. This would benefit consumers.

Additionally, we see no reason why a utility and its consumers should not have the ability to select, through a competitive procurement or solicitation process, an affiliate of a utility to build its plant. Why exclude or hamper competition for those most experienced in building and operating generating stations?

We are concerned that various interest groups are simply pointing out the risks and ignoring the advantages of a utility affiliate building power plants to meet the needs of others. Some of these groups say that the risk of cross-subsidization and self-dealing should preclude utility affiliates from participating in EWGs. NSP would like to remind the committee that prior to PURPA, all utility generation was supplied through self-dealing. Utilities built their own plants or purchased from other utilities, under the authority and regulation of state commissions and/or FERC. Given this history, concerns about self-dealing and cross-subsidization clearly can be managed directly without impeding IPP development in general.

The benefits of facilitating EWG development can be significant. NSP has a history of building some of the lowest cost power plants in the country with extremely low emissions. Why shouldn't we be able to utilize our expertise for the benefit of others? Competition, ingenuity, and comparative advantage can provide benefits to consumers and investors. We believe that changes to PUHCA would benefit consumers by maximizing supply options and would enhance overall energy security as the nation further diversifies its resource base.

TRANSMISSION ACCESS

Transmission access is often raised in discussions of PUHCA reform. However, we do not believe that PUHCA should address the issue.

Certainly, we believe that wholesale transmission access is vital to an efficient power supply system, needed both by suppliers and buyers of energy. We also believe that owners of transmission systems should not use their control to unfairly inhibit competition. But to include transmission access in PUHCA needlessly complicates the Act with issues that can be and are being effectively managed in other forums. For example, NSP has filed a transmission tariff with the FERC which guides the way we provide transmission service when capacity exists. We will provide transmission to any non-retail entity requesting service on a firm or interruptible basis. The rates we filed with FERC represent maximum rates to allow flexibility to discount as market conditions require. We believe this type of innovative and creative filing will enhance competition in the generation sector. Furthermore, FERC encourages voluntary transmission access, so it is not necessary for PUHCA to contain provisions addressing transmission access.

OTHER ISSUES

Other issues related to cross-subsidization and self-dealing have also been raised by various interest groups. We believe that existing state and federal regulatory authority is adequate to supervise the evolving marketplace. First, a generator exempt from PUHCA must receive FERC's approval of a power sales contract to obtain approval of wholesale rates. Second, states will regulate the way exempt generators conduct business in their states, and, finally, can even regulate the purchasing decision of the buying utility. We believe that this regulation constitutes three essential check points to ensure competition and protect against potential abuse. To the extent that potential abuses and remedies are identified to protect competition, strengthen regulation and make it more efficient, we stand ready to work with the Congress and affected interest groups to fashion a workable compromise. Our concern is that state and federal regulatory responsibilities are carefully delineated. We want to work with our state commissions on resource planning to assure careful review and analysis of decisions in advance of any actual commitments.

CONCLUSION

NSP supports amendment of the Holding Company Act which would exempt EWG power suppliers from the Act's regulatory requirements. We believe that this would maximize the nation's supply options and further diversify our nation's resource base.

STATE OF MICHIGAN

Commissioners
Steven M. Fetter
William E. Long
Ronald E. Russell

Public Service Commission
6545 Mercantile Way
P.O. Box 30221
Lansing, Michigan 48909-7504

John Engler, Governor
DEPARTMENT OF COMMERCE
P.O. Box 30004, Law Building, Lansing, Michigan 48909-7504
Arthur E. Ellis, Director

March 27, 1991

Honorable J. Bennett Johnston, Chairman
Committee on Energy and Natural Resources
SD-364 Dirksen Senate Office Building
Washington, D.C. 20510-6150

Dear Senator Johnston:

The attached document is the testimony of the Michigan Public Service Commission on proposed amendment of the Public Utility Holding Company Act of 1935 as embodied in Title XV of S. 341, the "National Energy Security Act of 1991." We respectfully request that our written comments be entered into the official record.

We appreciate the opportunity to submit these comments on this legislation.

Sincerely,

Steven M. Fetter, Chairman

William E. Long, Commissioner

Ronald E. Russell, Commissioner

Attachment

cc: Members, Senate Energy and Natural Resources Committee
Members, Michigan Congressional Delegation
Bill Conway, Senior Counsel, Committee on Energy and Natural Resources

UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES

Testimony of the
MICHIGAN PUBLIC SERVICE COMMISSION

on
S. 341, Title XV
PUBLIC UTILITY HOLDING COMPANY ACT REFORM

APPENDIX A

Excerpts From Commission Orders Containing Examples of Findings of Affiliate Abuses

Captions are provided to enhance the reader's understanding. They are not part of any of the referenced documents.

** DRAWING RESOURCES AWAY FROM UTILITY TO BENEFIT AFFILIATE **

"...following the financial stabilization orders in 1985, Consumers has effected a sweeping reorganization of its corporate structure, creating CMS Energy as its parent company, CMS Enterprises as a subsidiary of CMS Energy and sister to Consumers, and several new subsidiaries, including Midland Group Limited and MEC Development Company. Further, the MCV was also formed, and Consumers unilaterally assigned Midland plant assets at a booked value of approximately $1.5 billion to the MCV for purposes of developing a gas cogeneration plant at Midland, in conjunction with Dow Chemical and other partners. In more recent months, Consumers or its parent company, CMS Energy, has also undertaken a series of financial transactions aimed at transferring the booked Midland plant assets of Consumers (along with other financial and corporate assistance from Consumers) to the MCV, while at the same time ensuring that proceeds of those Midland plant assets would flow back, not to Consumers, but to its claimed unregulated parent company, CMS Energy. On the eve of expected Commission or court action relating to the Midland plant proceeds, CMS Energy purchased from Midland Group Limited, a wholly-owned subsidiary of Consumers, all of the capital stock of CMS Midland and MEC Development, in return for Midland Group Limited's receipt of a debenture of CMS Energy in the principal amount of $1.4 billion. Only after completion of this transaction did the MCV transfer $500 million of marketable notes to MEC Development, which also possesses the right to receive an additional $700 million of notes from the MCV. One potential result of these recent transactions is to deprive Consumers of any of the cash flow or other financial benefit from the transfer of Midland plant assets previously owned by Consumers to the MCV, which is inconsistent with our previous orders in Case No. U-7830 Step 3A providing financial stabilization relief designed to improve Consumers' cash flow."

U-7830 Step 3A et al., 3/27/90, p. 8-9.

** LACK OF ARM'S LENGTH BARGAINING **

"Consumers and the MCV would have this Commission believe that their power purchase agreement must be fair and reasonable because it resulted from "arm's-length" negotiations between the parties. However, the record does not support this conclusion. Rather, the record establishes that the Consumers/MCV contract did not result from arm's length negotiations...."

"Mr. Giffels described himself as MCV's chief negotiator.... While Mr. Giffels conducted "arm's length" negotiations on behalf of the MCV, he was reporting to Consumers' vice-president Cook....Mr. Giffels admitted that he drew his paychecks from Consumers for the first six to nine months of the bargaining period....The record shows that most, if not all, of the persons assisting Mr. Giffels in conducting his negotiations on behalf of the MCV were also being paid by Consumers....Other MCV officials also had important continuing ties to Consumers....the testimony reveals that Consumers had a dominent, controlling role in the MCV at the time of contract negotiations....The Commission observes that, unlike most arm's-length transactions, Consumers and the MCV share a commonality of interest. Specifically, both Consumers' shareholders and the MCV partners benefit from higher capacity rates and lenient contract provisions."

U-8871 et al., 1/31/89, p. 98-102.

"It is ...clear that the various transactions between Consumers and its parent company, CMS Energy, and their affiliates were not effected through arm's-length bargaining. All of these corporations are headed by the same individuals and by essentially the same senior staff. The blurring of corporate identities is illustrated by Mr. McCormick's response when asked if he is the chief executive officer of CMS Midland: "I'm not sure of that. I'm not denying it but I'm really not sure." (Tr. 278.)

U-7830 Step 3A and U-9611, 5/23/90, p. 32.

** SELF-DEALING RESULTING IN FAVORITISM TO AFFILIATE **

"It is apparent that the company's overwhelming corporate objective is to obtain Commission approval for as much as possible of the MCV capacity now and first priority for an additional 250 MW of MCV capacity when more capacity is needed, regardless of the interests of its ratepayers and the policies embodied in PURPA....One can only speculate whether the company would be as eager to put itself "at risk" for the additional 250 MW of MCV capacity if it did not own a substantial interest in the MCV....This Commission ...must...consider our responsibility to balance all interests, including those of the company's ratepayers.

In balancing those interests, the Commission flatly rejects any suggestion that the public interest and PURPA are well-served by a corporate policy that pursues maximum MCV capacity as its highest priority...."

U-8871 et al., Opinion and Order, 6/22/89, p. 20-21.

** OVERSUBSCRIPTION OF GENERATING CAPACITY RESULTING IN INEFFICIENCIES **

"....the company's proposed approach for additional MCV capacity provides significant opportunities for the company to affect the need for that capacity in ways that are not conducive to a rational energy policy for the state. If the company were so inclined, it could retire or derate capacity that it would not otherwise retire or derate; it could refuse to enter into new firm contracts for long-term capacity; it could enforce its contracts with qualifying facilities in ways designed to prevent or discourage their commercial operation; it could engage in marketing activities designed to increase summer peak demand; it could refuse to promote conservation and load management; and it could refuse to exercise its rights under its interruptible rates. In short, the company's proposal is not without significant risks that ratepayers will pay for the 250 MW of additional MCV capacity, regardless of whether there are reasonable opportunities to avoid the need for that capacity. Consumers' activities to date with regard to the MCV provide no basis to believe that the company will not seek additional ways to promote the interests of the MCV, and thereby Consumers' stockholders, at the expense of its ratepayers."

U-8871 et al., 6/22/89, p. 37-38.

** UTILITY ASSUMING RISK ON BEHALF OF AFFILIATE **

"A final concern related to the 352 MW of capacity, as well as the 250 MW of capacity, is Consumers' claim that its ratepayers are not at risk with respect to that capacity. The company acknowledges in its ancillary filing that if it is unable to find a market for both blocks of power, its potential financial exposure to the MCV is approximately $180 million per year. As pointed out by ABATE and the Attorney General, that is a significant sum of money for any utility, especially one that continues to obtain financial stabilization rate relief from its customers. It is therefore disingenuous for the company to claim that its customers are not at risk under a contract that requires Consumers to pay for electricity from the MCV whether there is a market for it or not."

U-8871 et al., 6/22/89, p. 40-41.

"...The utility...signed ten direct purchase contracts under which it planned to buy gas during 1989....the record reflects that Consumers had also been authorized to negotiate gas purchase contracts on behalf of the Midland Cogeneration Venture Limited Partnership (MCV), and had succeeded in obtaining contracts on behalf of the MCV with these same ten producers....

....First, the Commission finds that the contracts signed by Consumers and the MCV with each of these ten producers were negotiated as a package deal....Second, the record indicates that certain beneficial aspects of the MCV's gas purchase contracts were likely obtained at the expense of Consumers' sales customers. For example, a review of the MCV's supply contracts shows that...they did not require the MCV to purchase any minimum volumes of gas during 1988 and 1989. In contrast, Consumers' contracts with these same producers obligated the utility to begin purchasing gas immediately. This is despite the fact that, according to the utility's assessment...taking gas from these ten producers would leave Consumers significantly over-contracted until at least 1990....We therefore find that the utility's expected cost of gas from new direct supplies should be reduced by one-half of the projected cost differential, or $3,730,000."

U-9173, Opinion and Order, 5/3/90, p. 22-27.

** RESTRUCTURING HARMFUL TO REGULATED COMPANY **

"....In the spirit of the extraordinary rate increase, the Commission expected that Consumers would use all of its management skills, self-help, and financial and business opportunities to strengthen its utility operations and financial position, and Consumers' management provided an unqualified commitment to comply with the letter and the spirit of the conditions attached to the extraordinary Step 3A rate relief." [Consumers' electric rates are still not based on the cost of service and will not be until its pending rate case, Case No. U-9346 is concluded.]

"The testimony of Consumers' and CMS Energy's officers and the proposal offered by Mr. Fryling during rebuttal illustrate how far the current management of the company has moved from the spirit of Step 3A. Instead of using its resources to return the company to financial health, the company's management has pursued all conceivable legal and regulatory avenues to separate the benefits of improved financial health from the utility and to transfer them to the parent holding company, where they can be used in whatever way those managers see fit, even though Consumers has not yet achieved financial health and faces many near-term uncertainties that prudent managers would not ignore. What has developed is a concerted effort to prevent the utility from obtaining cash to meet its obligations and prepare for contingencies and, instead, to use the cash from Midland plant assets for non-utility enterprises. The Commission would not be carrying out its appropriate regulatory responsibilities if it quietly acquiesces to this course of action."

U-7830 Step 3A and U-9611, 5/23/90,
p. 41-42.

"....Among other things....Consumers transferred the usable assets but did not transfer the liabilities, which still remain on Consumers' books."

U-7830 Step 3A and U-9611, 5/23/90, p. 33.

** MISUSE OF RATEPAYER FUNDS **

"Also on March 12, 1990, unbeknownst to the Commission, CMS Energy and its various affiliates, including Consumers and its subsidiaries, engaged in financial transactions that would transfer to CMS Energy (and its affiliates), rather than to Consumers, the proceeds related to the transfer of Consumers' $1.5 billion in Midland plant assets to the MCV."

U-7830 Step 3A and U-9611, Opinion and
Order, May 23, 1990, p. 9.

** EXTENT OF HEARINGS AND AMOUNT OF RESOURCES **

"The hearings and prehearing conferences required 90 days. More than 60 parties participated and more than 100 witnesses testified. The record consists of 120 volumes of transcript, 14,383 pages, and 428 exhibits...."

U-8871 et al., Opinion and Interim
Order, 1/31/89, p. 9.

"The Commission's March 27, 1990 order commencing the comprehensive review proceedings is presently the subject of petitions for review filed in CMS Energy v MPSC, Ingham Circuit Court Docket No. 90-65964-AA; Consumers Power v MPSC, Ingham Circuit Court Docket No. 90-65963-AA; and MCV v MPSC, Ingham Circuit Court Docket No. 90-65959-AA."

U-7830 Step 3A and U-9611, Opinion and
Order, May 23, 1990, p. 9-12.

** IMPEDING COMMISSION REVIEW **

"The contested case process...exists to protect the rights of litigants in administrative proceedings. However, [it] was never intended to allow a regulated utility to escape regulation through regulatory delay. It is abundantly clear to the Commission from a review of the record in Case No. U-9322 and the legal maneuvering in the courts of this state that Consumers and CMS Energy, have, on one hand, utilized all appropriate and some inappropriate means to delay our review and determination of its compliance with the financial stabilization conditions and the letter and spirit of our decisions in Case No. U-7830 Step 3A, while at the same time they were racing ahead with efforts to circumvent the Commission's ability to thoroughly review and remedy any potential violations of the financial stabilization conditions."

U-7830 Step 3A et al., 3/27/90, p 15.

UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES

TESTIMONY

OF THE

MICHIGAN PUBLIC SERVICE COMMISSION

STEVEN M. FETTER, Chairman
WILLIAM E. LONG, Commissioner
RONALD E. RUSSELL, Commissioner

on

S. 341, Title XV

PUBLIC UTILITY HOLDING COMPANY ACT REFORM

Submitted for the Record

March 27, 1991

UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES

Testimony
of the
MICHIGAN PUBLIC SERVICE COMMISSION

on

S. 341, Title XV
PUBLIC UTILITY HOLDING COMPANY ACT REFORM

Mr. Chairman and Distinguished Members of the Committee:

Introduction and Purpose

The purpose of this testimony is to state our view that Title XV, as introduced, will not result in a workably competitive electric generation market because it will be subverted by self-dealing and other abuses between utilities and generating affiliates. The testimony also outlines some remedial actions which we believe would make the bill more likely to achieve the goal of a healthy competitive environment for independent generators.

The Michigan Public Service Commission (MPSC) is an agency of the State of Michigan, created by Act No. 3 of the Public Acts of 1939, M.C.L. 460.1 *et seq*.; M.S.A. 22.13(1) *et seq*., as the regulatory agency having jurisdiction and authority to control and regulate rates, charges and conditions of service for the sale and distribution of electricity in Michigan.

In addition to our responsibilities for regulating the ten investor-owned electric utilities and fourteen rural electric cooperatives in Michigan, we are responsible for regulating eleven natural gas companies, thirty-eight telephone companies, thousands of intrastate motor carriers and several water companies. We also operate some federal energy programs, serve as the coordination point with the United States Department of Energy with respect to energy emergency preparedness, and play a significant role in setting energy policy for the State of Michigan.

To aid us in carrying out these responsibilities on behalf of the 9.2 million citizens of Michigan, we have a staff of approximately 230 employees and an annual budget of approximately $16,000,000. Of the companies regulated by the MPSC, eight are part of utility holding companies as defined by the Public Utility Holding Company Act of 1935 (Holding Company Act or PUHCA).

Exemption of Utility Affiliate Generators From PUHCA Restrictions Will Foster Anti-Competitive Abuses

Michigan's experiences demonstrate abuses of exemptions currently available in PUHCA Section 3(a)(1) and Section 210 of the Public Utility Regulatory Policies Act (PURPA). During the last several years, we have gained significant experience with utilities and generating affiliates that have been exempted from the provisions of the Holding Company Act. Self-dealing and other anti-competitive abuses have been documented in several extremely complex cases before the Michigan Public Service Commission.

The majority of these cases relate to one utility holding company, CMS Energy Corporation (CMS Energy), its subsidiary, Consumers Power Company (Consumers), and numerous other affiliates. The volume, complexity and expense of litigation related to CMS Energy's activities is unprecedented. A disproportionate amount of MPSC staff, Attorney General, and other intervenor resources have been, and continue to be, expended on efforts to provide proper oversight and prevent unnecessary rates and risk from being assigned to Consumers Power Company by CMS Energy.

The activities of CMS Energy will be emphasized here because, of the Michigan utility holding companies, it is by far the most aggressive in testing the limits of applicable laws--both state and federal. Another utility has also been found by the Commission Staff to have significantly abused affiliate relationships to the detriment of the utility.* If the Holding Company Act is modified in such a way as to validate such actions, we fully expect to see other holding companies follow in the footsteps of their more adventurous brethren.

CMS Energy Corporation is a utility holding company with at least 40 subsidiaries and affiliates that we know about. The largest of these is Consumers Power Company, which is a combination electric and gas utility with approximate annual operating revenues of $1.7 billion from 1.4 million electric customers and $1.1 billion from 1.3 million gas customers (1989 Annual Report). In a January 1991 press release, CMS Energy described itself as "a $3 billion (sales) diversified energy holding company with businesses engaged in the distribution of electricity and natural gas, interstate storage and transmission of natural gas, oil and gas exploration and production, independent power generation and utility services."

CMS Energy has an intrastate exemption from the Holding Company Act. This exemption, in combination with the exemption for qualifying facilities under PURPA, has led to a proliferation of attempts to maximize shareholder profits at potential expense to ratepayers of Consumers Power Company. With these exemptions, corporate structure and transactions between corporate affiliates have been manipulated to nominally embrace the concept of competitive generation while attempting to ensure that all competitive advantages reside with holding company affiliates.

---

* It should be noted that this case, which involved Alpena Power Company, was ultimately resolved by a settlement agreement in which there was no admission of fault by the utility, although it agreed to modify its transactions with associated companies and reduce its rates by $1.1 million.

To give the Committee a flavor for what we have faced, several recent MPSC orders relating to CMS Energy affiliates are excerpted in Appendix A, which is attached to this testimony. Our Opinion and Order issued May 23, 1990 in Cases No. U-7830 Step 3A and U-9611 contains a more detailed history of the procedural and factual issues related to the proceeds from the Midland plant and some of the ways in which CMS Energy has tried to avoid appropriate state regulatory actions through the use of the utility holding company structure. A copy of this order is attached as Appendix B.

The types of abuses documented in cases before the Michigan Public Service Commission include:

- Drawing resources away from the utility to benefit affiliate(s);
- Lack of arm's length bargaining;
- Self-dealing resulting in favoritism to affiliate(s);
- Oversubscription of generating capacity resulting in inefficiencies;
- Utility assuming risk on behalf of affiliate(s);
- Misuse of ratepayer funds to benefit affiliate(s);
- Restructuring the corporation in ways that are harmful to the regulated utility; and
- Using the holding company structure to impede appropriate reviews by the state regulatory commission by:
    - Substantially increasing the complexity of cases;
    - Denying access to books and records of affiliates that have engaged in transactions with the utility;
    - Refusing to comply with lawful orders of the Commission; and
    - Engaging in a myriad of legal maneuvers in the courts.

Curbs on Utility Self-Dealing and Other Anti-Competitive Abuses Are Essential Elements of Any Successful Efforts To Create a Competitive Generation Market

We ask the Committee to bear in mind that the findings of self dealing and attempts to circumvent state regulation recited in Appendix A represent only a small portion of the activities of CMS Energy and affiliates with which the State of Michigan has had to contend.

To get an idea of the magnitude of the problem represented by the actions of just one exempt utility holding company, visualize an office of eleven government attorneys (on a limited budget) contending with proceedings before one state commission, at least three federal regulatory bodies, and both state and federal circuit and appellate courts versus up to 100 corporate and contractual counsel (budget virtually unlimited) operating on the opposite side of the same cases. Consider, too, that the eleven government attorneys are also responsible for representing the public in all of the other electric, gas, telephone and motor carrier cases presented to this Commission and the courts. This scenario approximates our current situation.

Now imagine how the government attorneys will cope if changes to the Holding Company Act encourage all ten of our investor-owned electric utilities to imitate, and perhaps embellish upon, the experiences of CMS Energy. Multiply this situation by the total number of investor-owned electric utilities in the country and you will have some idea of the potential effort required to protect the public interest if the Holding Company Act is amended as proposed.

We would argue that if Congress wishes to modify the Holding Company Act to encourage a competitive generation industry (a goal which we do not oppose), it should provide limits on the ownership of Exempt Wholesale Generators by transmission and distribution utilities in their own service territories and enhance the ability of state regulators to review transfers and transactions between utilities and their generating affiliates. These provisions would help ensure that fair competition emerges from amendments to the Holding Company Act.

Although our thinking on possible solutions to the problems we have outlined is not yet refined, in the spirit of making a positive contribution to the debate, we offer the following ideas for your consideration.

In his 1985 book, Utility Holding Companies, Douglas W. Hawes reports on some unimplemented guidelines for diversification of exempt holding companies proposed by two Securities and Exchange Commissioners in the Pacific Lighting Case (45 SEC 167 (1973)). Although the circumstances which prompted Commissioners Casey and Loomis to propose these guidelines are not entirely analogous to the current debate, the issues addressed are extremely relevant and represent one approach that is worthy of consideration by this Committee.

The Casey/Loomis guidelines are:

"1. All non-utility activities should be segregated from utility activities through separate corporate subsidiaries.

2. There should be no services, materials, or contracts between the utility and other subsidiaries except to the extent that such contracts are subject to the supervision of state regulatory agencies.

3. There should be no use of utility-operating management, funds, or credit for non-utility purposes.

4. Non-utility investments should constitute only a relatively small component of the entire system.

5. Activities should be either complementary in a significant way to the utility operations or have an established successful (i.e., profitable) record for a reasonable period of time."

Another approach would acknowledge that removing most of the generating sector from Holding Company Act purview would result in structural changes to the electric utility industry that are significant enough to require a realignment of regulatory responsibilities between state and federal regulatory agencies (both the SEC and the Federal Energy Regulatory Commission).

This kind of a system would require at least the following changes:

1. Explicitly grant to state regulatory commissions access to books and records of any utility holding company affiliates that transact business with the utility.

2. Create some mechanism that would allow tracking of costs between geographically dispersed utility affiliates.

3. Return regulation of intrastate wholesale electric rates to the states. This will be appropriate because, if a competitive generation market is successfully created, most of the costs that are passed on to retail ratepayers will derive from transactions between a utility and a non-utility generator that very frequently will be located in the same state as the purchasing utility.

4. Retain some limits on the complexity of corporate structures that involve utilities. Unless Congress decides that it wants to help states fund greatly expanded regulatory staffs, the public interest requires that reasonable limits on the extent and complexity of utility holding companies be enforced. Failure to do this will not only place insurmountable obstacles in the paths of state regulators, but will ultimately result in an unhealthy contraction of the generating sector into the hands of a few unregulated but monopolistic national holding companies.

We appreciate the opportunity to present our views for the record in this hearing on S. 341, Title XV. We hope that the Committee will find value in our comments as it considers modifications to the Public Utility Holding Company Act of 1935 to better serve the public interest.

APPENDIX B

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **CONSUMERS POWER COMPANY** for authority to increase its rates applicable to the sale of electricity.

Case No. U-7830
Step 3A

In the matter of the application of **CONSUMERS POWER COMPANY** for determination of the dispostion of proceeds from certain Midland plant assets.

Case No. U-9611

At a session of the Michigan Public Service Commission held at its offices in the city of Lansing, Michigan, on the 23rd day of May, 1990.

PRESENT: Hon. William E. Long, Chairperson
Hon. Steven M. Fetter, Commissioner
Hon. Ronald E. Russell, Commissioner

OPINION AND ORDER

I.

BACKGROUND

Introduction

This final order of the Commission is entered in special proceedings commenced pursuant to the March 29, 1990 bench opinion and April 26, 1990 order of Ingham Circuit Court Judge Thomas L. Brown in Attorney General v CMS Energy et al., Ingham Circuit Court Docket No. 90-65769-CZ. Judge Brown's order enjoined a transfer to CMS Energy or its subsidiaries of certain proceeds arising from the transfer by Consumers Power Company (Consumers) of $1.5 billion of Midland plant assets to the Midland Cogeneration Venture Limited Partnership (MCV), and required the Commission to commence and complete within 45 days a contested case concerning the legal and factual issues relating to the use of the MCV proceeds. A complete procedural history follows.

Procedural History

The genesis of this case was the failure of Consumers' Midland nuclear plant construction project and the ensuing financial reorganization of Consumers in which the utility's ratepayers participated pursuant to this Commission's financial stabilization orders in Case No. U-7830 Step 3A, which granted Consumers substantial and extraordinary rate relief over and above rates based upon cost-of-service principles, subject to terms and conditions specifically agreed to by Consumers. As explained below, these conditions included condition 11, which required Consumers to submit for Commission review and approval the utility's proposed use of any proceeds obtained from the disposition of any Midland plant assets or litigation.

In July 1984, Consumers ceased construction of the Midland nuclear power plant. The company found itself in a precarious financial condition and asked the Commission to grant rate relief of $205 million per year for the indefinite future to permit the company to avoid bankruptcy. Following extensive hearings and arguments on that request, the Commission issued an order on March 29, 1985 providing that if Consumers would comply with conditions designed to help it return to financial health, the Commission would authorize a six-year increase of $99 million per year.

As described by the Commission, the rate relief would be an extraordinary and unprecedented increase that was not based upon cost-of-service principles, but was designed to provide additional cash flow to assist Consumers in avoiding bankruptcy, to ensure adequate service to its ratepayers, and to assist with the financial stabilization of the company. The rate relief was necessary also because the $4.2 billion investment by Consumers in the abandoned nuclear plant distorted Consumers' entire capital structure. Moreover, the financial stabilization rate relief was an important part of a non-bankruptcy financial reorganization and rescue package that was agreed to by Consumers and its creditors and financially supported by its ratepayers pursuant to the orders of this Commission.

The Commission's order recognized that the rate increase alone would not be enough, but that Consumers and its shareholders would have to fully participate in the financial rescue by reducing expenses and temporarily eliminating dividends, using the savings to pay off debt and other obligations, and taking other appropriate actions. (To permit the company to use those savings and additional revenues, the Commission did not in later cases reduce electric rates to reflect lower tax expenses due to tax losses, lower operation and maintenance expenses, and lower interest expenses.) The Commission's March 29, 1985 order also established 12 conditions that Consumers was required to adhere to in order to collect the financial stabilization surcharges, to all of which Consumers agreed. The 12 conditions prescribed in the order were designed to ensure, to the maximum extent possible, that ratepayers would receive the benefits for which they were paying, a financially healthy utility company, and that they would be protected from carrying an undue share of the burden of financial stabilization. Among the conditions were requirements that the company restructure its debts and repay $1.9 billion of bank debt and other obligations, not resume construction at the Midland plant, work toward a balanced capital structure, and not resume a normal dividend until the company had returned to financial health and was no longer collecting financial stabilization rate relief. The conditions also included matters relating to the company's financial transactions with its subsidiaries. Among the conditions was condition 11, which specifically required Consumers to file an application with the Commission to determine the proper use of Midland plant proceeds within 45 days of the earlier of receiving, directly or indirectly, any Midland plant proceeds or notice of the date on which it would receive any such proceeds. Specifically, condition 11 of the March 29, 1985 order, pages 43-44, stated:

> "Within 45 days of the earlier of receiving, directly or indirectly, any proceeds or notice of the date on which it will receive proceeds from the sale or salvage of the Midland plant, its fuel or related facilities, or from litigation related to their construction or fabrication, Consumers shall file an application specifying how it proposes to use the proceeds. The Commission will schedule a hearing and at the conclusion issue an order specifying the use of those funds. Other issues as appropriate may also be addressed in those hearings."

It is this condition that resulted in both the Commission's and the Circuit Court's directing Consumers to file an application with respect to the proceeds received from the MCV for Midland plant assets.

The Commission's July 24, 1985 follow-up order in Case No. U-7830 Step 3A specifically found that Consumers had complied with the requirements that were prerequisites to commencing collection of the financial stabilization surcharges, including the filing by Consumers of express written agreement to the conditions of the financial stabilization order. Consumers accomplished this by filing certain affidavits of its senior management and a resolution of its Board of Directors, pledging to abide by the letter and spirit of the Commission's order. Based on Consumers' compliance, the Commission's July 24, 1985 order authorized the company to commence collecting the financial stabilization surcharges in the amount of $94 million annually, effective upon the closing date of the debt restructuring agreement, August 24, 1985. (The original plan approved by the Commission's March 29, 1985 order provided for an annual rate increase of $99 million; however, pursuant to conditions 7 and 11, a reduction of $5 million per year was approved by the Commission as an interim disposition of the proceeds from the sale of nuclear fuel. See July 24, 1985 order in Case No. U-7830 Step 3A, p. 17.)

The Commission's March and July 1985 financial stabilization orders in Case No. U-7830 Step 3A also required annual contested case proceedings to scrutinize Consumers' financial transactions and to ensure compliance with the conditions attached to the special rate relief. The orders specifically required Consumers to file by March 15 of each year a report showing that, during the preceding year, Consumers had complied fully with the conditions of financial stabilization rate relief and an application to commence a contested case to review compliance during that year.

On March 11, 1986, the Commission issued an order in Case No. U-8249 further reducing the annual amount of the financial stabilization rate relief from $94 million to $91 million, in accordance with conditions 7 and 11, due to the disposition of Midland nuclear fuel.

On March 14, 1986, Consumers filed its first financial stabilization compliance report and application, commencing the 1985 annual compliance proceeding, Case No. U-8431. Shortly thereafter, on April 8, 1986, Consumers filed a motion for relief from condition 5, which prohibited a resumption of construction at the Midland plant without prior approval from the Commission. The motion sought approval to resume construction of the Midland plant as a natural gas-fired, combined-cycle generating plant.

On October 22, 1986, the Commission issued an order in Cases Nos. U-7830 Step 3A, U-7830 Step 3B, and U-8431, granting partial relief from condition 5. The order permitted Consumers to participate in the construction project, subject to the company's agreement to abide by certain voluntary undertakings that it had offered in a filing to the Commission, including commitments that the company would not use ratepayer funds, would not spend more than $50 million on the project, would not at any time seek a rate increase to recover from its customers for the construction, and would meet its commitment under the Commission's March 29, 1985 order to repay $1.9 billion of fixed obligations. The order contained no language approving, authorizing, or supporting the company's decision to pursue the new project; nor was there any finding regarding its prudence. Those questions were not before the Commission. Consumers did not ask the Commission to decide how the company should proceed. Completion of the plant as a cogeneration facility outside of Consumers' rate base was the company's choice, not the Commission's.

Also on October 22, 1986, the Commission issued an order in Case No. U-8431 reviewing the company's compliance with the financial stabilization conditions in 1985 and finding compliance based upon the then-existing record. In the course of reviewing the company's compliance, the Commission addressed condition 11 and the company's position that "proceeds" only means "cash proceeds". The Commission stated:

> "While Consumers' view of 'proceeds' does not affect the outcome of this compliance case, the Commission disagrees with its interpretation. The Commission did not intend 'proceeds' to mean only 'cash proceeds'. It may be that non-cash proceeds should be handled differently than cash proceeds. That is an issue the Commission will not decide until it has full argument before it at the conclusion of the first case held to determine the use of Midland plant proceeds." (October 22, 1986 order in Case No. U-8431, p. 12.)

Consumers' 1986 and 1987 compliance reports acknowledge the Commission's definition that proceeds include non-cash items as well as cash.

On March 31, 1987, the Commission issued an order in Case No. U-8249, in accordance with conditions 7 and 11, further reducing the financial stabilization surcharges to $90 million, to recognize the final resolution of proceeds from disposition of the Midland nuclear fuel.

On August 23, 1988, the Commission issued its order in Cases Nos. U-8630 and

U-8713, reducing the financial stabilization surcharges to approximately $78 million annually to recognize proceeds from the sale and salvage of Midland plant assets other than the nuclear fuel.

On September 13, 1988, the Commission issued its order in Case No. U-8721, commenced by Consumers' March 13, 1987 compliance report and application, finding Consumers to be in compliance with the conditions of the Step 3A financial stabilization order for 1986, based upon the then-existing record. In connection with condition 11, the Commission's order addressed Consumers' argument related to any funds it might receive as a result of dismissal of its lawsuit with The Dow Chemical Company (Dow) related to construction of the Midland plant. The Commission stated: .

> "The Dow lawsuit was pending at the time of the Commission's March 29, 1985 order and it relates to construction of the Midland plant. Similarly, proceeds received from the transfer of the Midland plant property are within the scope of condition 11, unless Consumers has a more persuasive reason than it has offered in this case. Consumers therefore must continue to reflect all proceeds in its monthly filings and must place them at issue in appropriate contested cases." (September 13, 1988 order in Case No. U-8721, p. 19.)

On May 23, 1989, the Commission issued its order in Cases Nos. U-7830 Step 3A and U-9040, commenced by Consumers' March 15, 1988 compliance report and application for 1987. The Commission's order found Consumers to be in compliance with the conditions of the Commission's Step 3A financial stabilization order for 1987, based upon the then-existing record. In connection with condition 11, the Commission's order addressed Attorney General Frank J. Kelley's (Attorney General) request "that the Commission should reject the company's attempt to have condition 11 apply to abandoned Midland plant assets, but not those assets conveyed to the MCV." The Commission responded that "condition 11 is clear; it applies to all Midland plant proceeds." (May 23, 1989 order in Cases Nos. U-7830 Step 3A and U-9040, p. 22.)

On March 15, 1989, Consumers filed its application for compliance year 1988 in Case No. U-9322. Following notice, contested case proceedings commenced and are still pending. On December 12, 1989, one of the parties, the Association of Businesses Advocating Tariff Equity (ABATE), filed a motion requesting that Consumers' rates be reduced by eliminating the $78 million financial stabilization surcharge. ABATE filed a subsequent pleading, dated January 3, 1990, again urging emergency review of its request that Consumers' financial stabilization surcharges be eliminated because of the impending receipt by Consumers of approximately $1.2 billion in notes resulting from the sale of Midland plant assets to the MCV. ABATE's pleadings also raised issues concerning further steps that should be considered to deal with the proceeds received from the MCV transaction. On January 18 and 24, 1990, Consumers filed responses to ABATE's pleadings.

On January 29, 1990, this Commission issued an order in Case No. U-9322 addressing the pleadings filed by ABATE, which were also supported by the Attorney General, concerning the impending receipt of proceeds from the MCV, among other issues, and ordering that an expedited hearing schedule be set for receiving evidence and briefs concerning the Midland plant proceeds and the ramifications of the receipt of those proceeds for the Commission's financial stabilization order. The Commission's order established February 12, 1990 for receiving prefiled testimony; February 21, 1990, for the hearing; and March 2 and 9, 1990, for the filing of briefs.

On February 7, 1990, Consumers filed a motion to delay the proceedings established by the Commission's January 29, 1990 order in Case No. U-9322, which was denied by the Commission's order dated February 21, 1990. Consumers then filed three separate cases in the Ingham Circuit Court seeking an order of superintending control against the Commission's January 29 and February 21, 1990 orders, in addition to a stay of the orders and other relief. (Consumers Power v MPSC, Ingham Circuit Court Docket No. 90-65502-AA; Consumers Power v MPSC, Ingham Circuit Court Docket No. 90-65651-AS; and Consumers Power v MPSC, Ingham Circuit Court Docket No. 90-65652-AS.) Consumers' request for superintending control was denied by Ingham Circuit Court Judge James R. Giddings in his bench opinion issued on March 15, 1990.

On March 12, 1990, Consumers filed in Case No. U-7830 Step 3A a motion to terminate financial stabilization, seeking to reduce its financial stabilization surcharges to zero effective immediately. Consumers' application also stated Consumers' view that the prospective elimination of financial stabilization surcharges should eliminate the need for further review of whether Consumers had adhered to the financial stabilization conditions. Consumers' March 12, 1990 application also stated that Consumers would soon file a motion to terminate the Case No. U-9322 proceedings for compliance year 1988 and that Consumers would not be filing any compliance reports or applications for subsequent years in which it received financial stabilization revenues, including 1989 and a portion of 1990.

Also on March 12, 1990, unbeknownst to the Commission, CMS Energy and its various affiliates, including Consumers and its subsidiaries, engaged in financial transactions that would transfer to CMS Energy (and its affiliates), rather than to Consumers, the proceeds related to the transfer of Consumers' $1.5 billion in Midland plant assets to the MCV.

On March 13, 1990, based upon Consumers' March 12, 1990 motion to terminate financial stabilization surcharges, the Commission issued its order in Case No. U-7830 Step 3A reducing Consumers' financial stabilization surcharges to zero, effective March 12, 1990. The Commission's order specifically did not terminate other aspects of the financial stabilization compliance proceedings; the Commission did not make a finding that Consumers no longer needed the rate relief; it did not find that Consumers had repaid $1.9 billion of bank debt and other obligations as required by the March 29, 1985 order; and it did not find that Consumers had reached financial health.

On March 14, 1990, the Attorney General filed a complaint in the Ingham Circuit Court and obtained a temporary restraining order against CMS Energy, the parent company of Consumers, CMS Enterprises,[1] Consumers, their affiliates, and their related entities and officers, restraining any transfer of proceeds from the MCV pending completion of the Commission's review of the transactions and further orders of the Court. The Court's temporary restraining order, issued in Attorney General v CMS Energy et al., Ingham County Circuit Docket No. 90-65769-CZ also provided for its expiration on March 28, 1990, and set the same date for a hearing concerning whether a preliminary injunction should be issued to restrain the transfer of proceeds for a longer period.

On March 15, 1990, CMS Energy and its affiliates filed an emergency appeal in the Michigan Court of Appeals (Attorney General v CMS Energy et al., File No. 126774) seeking to overturn the lower court's temporary restraining order, which was denied by the appellate court's order dated March 16, 1990. Also on March 16, 1990, pursuant to further proceedings in the Ingham Circuit Court, the Circuit Court modified its temporary restraining order, based upon the stipulation of all parties, to permit the MCV to proceed with a partial sale and leaseback involving the issuance of certain pollution control bonds, but otherwise keeping intact the general restrictions established in the March 14, 1990 temporary restraining order.

On March 27, 1990, the Commission issued an opinion and order commencing a comprehensive contested case review of Consumers' compliance with the Commission's financial stabilization orders in Case No. U-7830 Step 3A based upon motions filed by various parties to Case No. U-9322 and upon information revealed in court litigation and pronouncements and filings of Consumers. The motions included ABATE's March 14, 1990 motion for clarification and a renewed motion for emergency relief, which asked the Commission to clarify certain aspects of its March 13, 1990 order and to immediately act upon its previous emergency requests in Case No. U-9322 seeking a Commission order to restrict Consumers from using or directing the use of the approximately $1.2 billion of proceeds from the MCV. Among other things, the Commission's March 27, 1990 order directed Consumers to file an application with respect to the proceeds to be received for Midland plant assets that have become part of the MCV project. To protect ratepayers' interest during the interim, the Commission ordered Consumers, CMS Energy, and their subsidiaries and affiliates to refrain from transferring any proceeds received from the sale of Midland plant assets. The March 27, 1990 order also provided for review of Consumers' compliance with the Commission's financial stabilization orders for compliance years 1988, 1989, and 1990. The Commission's March 27, 1990 order (pp. 8-9) also described what had come to light concerning the sudden corporate transactions undertaken on March 12, 1990 by CMS Energy, Consumers, and their affiliates, as follows:

---

[1] On February 26, 1987, Consumers filed articles of incorporation for CMS Energy Corporation and CMS Enterprises Company. As a result of a reorganization, Consumers and CMS Enterprises became subsidiaries of CMS Energy.

> "The Commission finds, based upon the record compiled thus far in Case No. U-9322, including hearings on the various motions and discovery disputes and the pleadings filed in the recent court actions referenced above, that a number of significant factual and legal issues exist relative to Consumers' compliance, or noncompliance, with the conditions and requirements of the Commission's financial stabilization orders in Case No. U-7830 Step 3A and the subsequent annual compliance cases. For instance, following the financial stabilization orders in 1985, Consumers has effected a sweeping reorganization of its corporate structure, creating CMS Energy as its parent company, CMS Enterprises as a subsidiary of CMS Energy and sister to Consumers, and several new subsidiaries, including Midland Group Limited and MEC Development Company. Further, the MCV was also formed, and Consumers unilaterally assigned Midland plant assets at a booked value of approximately $1.5 billion to the MCV for purposes of developing a gas cogeneration plant at Midland,

> in conjunction with The Dow Chemical Company (Dow) and other partners. In more recent months, Consumers or its parent company, CMS Energy, has also undertaken a series of financial transactions aimed at transferring the booked Midland plant assets of Consumers (along with other financial and corporate assistance from Consumers) to the MCV, while at the same time ensuring that proceeds of those Midland plant assets would flow back, not to Consumers, but to its claimed unregulated parent company, CMS Energy. On the eve of expected Commission or court action relating to the Midland plant proceeds, CMS Energy purchased from Midland Group Limited, a wholly-owned subsidiary of Consumers, all of the capital stock of CMS Midland and MEC Development, in return for Midland Group Limited's receipt of a debenture of CMS Energy in the principal amount of $1.4 billion. Only after completion of this transaction did the MCV transfer $500 million of marketable notes to MEC Development, which also possesses the right to receive an additional $700 million of notes from the MCV. One potential result of these recent transactions is to deprive Consumers of any of the cash flow or other financial benefit from the transfer of Midland plant assets previously owned by Consumers to the MCV, which is inconsistent with our previous orders in Case No. U-7830 Step 3A providing financial stabilization relief designed to improve Consumers' cash flow."

The Commission's March 27, 1990 order commencing the comprehensive review proceedings is presently the subject of petitions for review filed in CMS Energy v MPSC, Ingham Circuit Court Docket No. 90-65964-AA; Consumers Power v MPSC, Ingham Circuit Court Docket No. 90-65963-AA; and MCV v MPSC, Ingham Circuit Court Docket No. 90-65959-AA.

On March 28 and 29, 1990, hearings were held in Ingham Circuit Court Docket No. 90-65769-CZ before Judge Brown relative to the Attorney General's motion to extend the temporary restraining order and to obtain a preliminary injunction to prohibit the transfer of any Midland plant proceeds pending the completion of Commission proceedings pursuant to condition 11. On March 29, 1990, Judge Brown issued his bench opinion granting the Attorney General's requested relief, which was finalized by Judge Brown's April 26, 1990 order of preliminary injunction. The Court's opinion provided that the March 16, 1990 modified temporary restraining order would continue in effect, and established an expedited 45-day schedule of proceedings for the Commission to undertake a review of the issues relating to the proceeds obtained from the Midland plant-related MCV transactions. On May 21, 1990, the Court approved a stipulation of the parties extending to May 23, 1990 the time for the Commission to issue its order.

The effect of the Circuit Court's April 26, 1990 order was to carve out of the comprehensive proceedings commenced by the Commission's March 27, 1990 order in the consolidated financial stabilization compliance dockets those issues that relate to the proceeds obtained by Consumers from the sale of Midland plant assets to the MCV project. All legal and factual issues relating to other condition II proceeds (other than MCV-related proceeds), such as proceeds related to the settlement of litigation, will continue to be the subject of the other Commission hearings in the consolidated proceedings established by the Commission's March 27, 1990 order.

Pursuant to the schedule required by Judge Brown's opinion, Consumers, on April 4, 1990 filed a pleading styled as an application under protest to commence this proceeding, which was followed by the Commission's April 6, 1990 procedural order commencing this special case and establishing the hearing and briefing schedule.

On April 12, 1990, Consumers filed its emergency appeal, as later supplemented, of Judge Brown's opinion and orders in the Court of Appeals, File No. 127719, which was denied by the Court's order dated May 9, 1990. Consumers filed an emergency motion for rehearing of the order, on which the Court has not yet ruled.

Prehearing conferences were held in this case on April 18, 20, and 27, 1990 before Administrative Law Judge Frank V. Strother (ALJ). The direct testimony of the witnesses was presented on April 30 and May 1 and 2, 1990. William T. McCormick, Jr. and Victor J. Fryling testified for CMS Energy. Blake O. Fisher testified for Consumers. Dr. Ben Johnson testified for the Attorney General, Dr. Hasso C. Bhatia testified for the Commission Staff (Staff), and H. Clyde Allen testified for ABATE. Rebuttal testimony was presented by Steven H. Lasher for the MCV and Mr. Fryling for CMS Energy on May 4, 1990. Consumers, CMS Energy, the MCV, ABATE, the Attorney General, and the Staff filed briefs on May 11, 1990 and reply briefs on May 16, 1990.

Proceeds Transactions

In January and August 1987, Consumers transferred Midland plant assets that it determined would be usable in the MCV project to two of its subsidiaries, CMS Midland, Inc., incorporated on December 2, 1986, and MEC Development Corporation, incorporated December 15, 1986, at a book value of approximately $1.5 billion. In exchange, it received all of the stock of the two corporations. On April 20, 1988, Consumers formed a new subsidiary, MCL, which became the owner of all CMS Midland and MEC Development stock on April 25, 1988.

In September 1989, CMS Energy announced that it would receive approximately $1.2 billion in marketable securities in exchange for certain Midland plant assets held by MEC Development for transfer to the MCV. In December 1989 and January 1990, ABATE filed two motions alleging that because of the imminent receipt of $1.2 billion in notes, the financial stabilization surcharges should end. ABATE also requested the Commission to restrict use of those notes until Consumers filed an application regarding the disposition of the proceeds. On February 21, 1990, a hearing in Case No. U-9322 was conducted to consider the issues raised by ABATE's motions. The Staff, ABATE, and the Attorney General asserted that any proceeds resulting from the sale of Midland plant assets are subject to condition 11. Consumers denied that receipt of the notes would require it to file a condition 11 application.

In his prefiled testimony for the February 21, 1990 hearing, Consumers witness Fisher stated that "MEC Development certainly hopes that the . . . notes would be issued within a period of 60-90 days after the actual commercial operation" of the MCV project. But "a hope is not the same as a reasonable expectation." (Exhibit A-33, p. 2814.) During cross-examination, he was asked whether Consumers had any plans to sell the stock of MGL. He stated that Consumers "has evaluated that possibility. It is currently restricted, under an agreement that it's made with the banks, . . . in its ability to do that." (Exhibit A-33, p. 2850.) He was then asked whether MGL had plans to sell the stock of CMS Midland or MEC Development. Mr. Fisher said, "Not to my knowledge." (Exhibit A-33, p. 2851.) In response to another question, he acknowledged that it was not impossible that the notes could be received within the next 60 days. (Exhibit A-33, p. 2851.) On March 2, 1990, Consumers filed its brief related to the February 21, 1990 hearing and represented that there was uncertainty about when the MCV notes would be received. On March 8, 1990, the CMS Energy and Consumers boards of directors met and authorized the transfer of CMS Midland and MEC Development to CMS Energy to "insulate cash from confiscation." (Exhibit I-1.) On March 9, 1990, Consumers filed its reply brief related to the February 21, 1990 hearing and stated that the possibility of receiving proceeds at an unspecified future date did not constitute notice of when it would receive proceeds.

On March 12, 1990, CMS Midland transferred to the MCV the Midland plant assets it owned in exchange for a 49% equity interest in the partnership. MEC Development transferred to the MCV the Midland plant assets it owned in exchange for approximately $500 million of notes and a commitment to receive approximately another $730 million of notes. Issuance of the $500 million of notes depended on satisfying conditions in the construction loan agreement, which was accomplished by replacing that loan with "bridge" loan financing. Issuance of the $730 million of notes depends on removing restrictions in the "bridge" loan financing. Also on March 12, 1990, MGL transferred its stock in CMS Midland and MEC Development to CMS Energy in exchange for a $1.4 billion CMS Energy debenture, payable over 15 years. By its terms, MGL cannot sell the debenture for 18 months and, for the first 3 years, CMS Energy has the option to pay interest in kind by issuing additional debentures.

Until Consumers filed its April 4, 1990 application under protest, it had not filed a condition 11 application with respect to any of these transactions.

Sale and Leaseback Transaction

The MCV is a limited partnership formed to construct a 1,370 Megawatt natural gas-fired cogeneration facility in Midland, Michigan. The facility uses approximately $1.5 billion of assets that were originally part of the Midland nuclear plant. The MCV facility is being constructed in two stages. The first stage includes eight gas turbines and recovery boilers, one of the steam turbines from the abandoned nuclear plant, and certain pollution control and related equipment. The first stage went into commercial operation on March 16, 1990. The second stage includes four additional gas turbines and recovery boilers, a second steam turbine, and certain related equipment. The second stage facilities will go into commercial operation as the equipment becomes operational.

The MCV has explored alternatives for permanent financing of the facility and has selected a sale and leaseback method, a financing arrangement designed to make maximum use of available tax benefits. According to the MCV, it will sell substantially all of the fixed assets of the facility to five owner trusts, which will then lease the facility back to the MCV, which will continue to operate it. The first phase of the sale and leaseback involves approximately $260 million of pollution control assets and other assets, and it was completed on March 16, 1990, coincident with the commercial operation of the first stage assets.

As described by the MCV, the remaining phase of the sale and leaseback involves approximately $2 billion of assets and must occur within three months of March 16, 1990 for the new owners of the facility to claim accelerated depreciation over a five-year period and an immediate 6.5% investment tax credit on eligible equipment. The MCV states that the tax law prevents the partners from simply transferring the tax benefits to other entities through a sale of their partnership interests and that certain of the MCV partners are not in a position to utilize the tax benefits. As a result, it says the only way to preserve the value of the tax benefits is through completion of the sale and leaseback.

CMS Midland is one of seven partners in the MCV, with a 49% partnership interest. CMS Midland received its partnership interest in exchange for the contribution of Midland plant assets having a value of approximately $341 million. If the sale and leaseback goes forward, CMS Midland will receive a cash distribution from the MCV of approximately $300 million. Approximately $200 million of this will be reinvested by another CMS Energy subsidiary, CMS Midland Holdings Company (incorporated March 12, 1990), as one of the new lease equity investors having a beneficial interest in one of the owner trusts. It is expected that CMS Midland Holdings will have at least a 35% interest in the total lease equity. After the sale and leaseback, CMS Midland will hold a partnership interest valued at approximately $41 million and $100 million in cash. CMS Midland Holdings will have a lease equity interest of approximately $200 million. If the sale and leaseback does not occur, CMS Energy, through its subsidiaries, will have a 49% interest without receiving cash immediately.

MEC Development entered into an agreement with the MCV to transfer certain

Midland plant assets in exchange for a debt interest in the project. Prior to March 12, 1990, notes could not be issued to it because of restrictions in the construction loan agreement. On March 12, 1990, the MCV arranged "bridge" loan financing that permitted the issuance of $500 million of notes to MEC Development. Pursuant to agreement with the MCV, the remaining notes will be issued for approximately $730 million. Those notes will be issued when the "bridge" loan is paid off and permanent financing is arranged. If the sale and leaseback goes forward, the additional $730 million of notes will be issued by the MCV to MEC Development. It will then exchange those notes for notes of "substantially equivalent marketability and value" (Exhibit I-18) issued by Midland Funding Corporation. For tax reasons, MEC Development must be able to commit at the time of the closing of the sale and leaseback to sell those notes to unrelated third parties prior to the end of 1991. Thus, with respect to the debt interest of CMS Energy subsidiaries in the MCV, the effect of the sale and leaseback is that before the sale and leaseback, MEC Development has $500 million of notes and a right to receive approximately $730 million of notes if certain conditions are satisfied. After the sale and leaseback, MEC Development has approximately $1.23 billion of notes. In the opinion of Consumers witness Fisher, the debt received by CMS Energy subsidiaries as a result of the sale and leaseback will be as valuable as the notes from the MCV and probably more valuable because the terms of the debt under the sale and leaseback, he believes, are somewhat more favorable to MEC Development.

Positions of the Parties

The position of Consumers is that proceeds for purposes of condition 11 only means cash. As a result, it asserts that it does not have proceeds from the disposition of the Midland plant assets to the MCV. The company's position is that when it receives cash as a result of the CMS debenture, that cash may be used for general corporate purposes: e.g., to fund construction, to pay dividends to CMS Energy, and to repay its obligations. In its view, it is unnecessary at this time to allocate a greater portion of the Midland plant proceeds for the use of the utility and to assure the utility's return to financial health because over time the debenture will pay interest and principal to a subsidiary of Consumers, which in turn will be able (but not required) to use that cash as necessary for maintaining a balanced capital structure and meeting the other needs of the utility company.

CMS Energy, participating pursuant to a notice of limited appearance, states that it is a party to the Circuit Court case, but denies that the Commission has jurisdiction to make it a party to this proceeding. CMS Energy did avail itself of the opportunity to file testimony, but it claims that it has done so without becoming a party and without waiving or abandoning its position that any action this Commission has taken or may take with regard to it and its non-utility subsidiaries is "completely unlawful" and beyond the jurisdiction of the Commission.

CMS Energy nevertheless asserts that it made an extraordinary effort to assist the Commission in resolving this case. It states that it cooperated by providing the testimony of its Chairman of the Board of Directors and Chief Executive Officer, William T. McCormick, Jr., and its Executive Vice President and Chief Financial Officer, Victor J. Fryling. (They hold the same positions with Consumers.) It also states that it voluntarily permitted its documents to be produced by Consumers for purposes of discovery and that it agreed to produce Mr. Fryling for a deposition. It points out that, through the rebuttal testimony of Mr. Fryling, it presented a proposal that would have MGL provide a $100 million cash dividend to Consumers if the sale and leaseback occurs.

CMS Energy asserts that its various subsidiaries are separate legal corporations and that neither CMS Energy nor any of its subsidiaries other than Consumers was ever subject to financial stabilization conditions. CMS Energy points out that it was not in existence in 1985 and the Commission has never requested that CMS Energy indicate acceptance of the financial stabilization conditions. With respect to the conditions that applied to Consumers, the company asserts that ABATE, the Attorney General, and the Staff do not show how their proposals are consistent with the conditions of financial stabilization and the Commission's jurisdiction. CMS Energy believes that even if the Commission has jurisdiction, no further action by the Commission is necessary or appropriate under the principles of financial stabilization.

CMS Energy disagrees with the characterization of financial stabilization as a "bargain" or "deal" that was struck in 1985 between the Commission and Consumers. CMS Energy views the financial stabilization rate relief as an exercise of the Commission's ratemaking jurisdiction and as such fully subject to the prohibition against retroactive ratemaking. CMS Energy argues that the Commission cannot unilaterally and retroactively change the terms of the bargain by stating that what the Commission really meant was something other than what its orders said when establishing financial stabilization. CMS Energy asserts that the 1985 orders, which preceded the initiation of the financial stabilization surcharges, indicate that, with the exception of condition 5, the financial stabilization conditions were conditions precedent to the continuing receipt of financial stabilization revenues and therefore would not survive the end of financial stabilization; that even during financial stabilization, the Commission did not intend to interfere with the prerogative of the officers and directors of Consumers to manage the utility; and that for purposes of condition 11, proceeds meant only cash or the equivalent of cash.

In its brief, the MCV says that it is participating solely in an effort to prevent this case from "causing the MCV partners enormous and irreparable harm." The MCV repeats the request from its April 18, 1990 motion for clarification of the March 27 and April 6, 1990 orders, and requests the Commission to clearly state that it did not intend to prevent or impede the completion of the sale and leaseback. The MCV asserts that no one has raised any substantive objection to the sale and leaseback, that the sale and leaseback preserves rather than dissipates the proceeds, that preventing the sale and leaseback will cause enormous injury to the MCV and its partners, and that completion of the sale and leaseback will harm no one and is in the interests of all parties.

The Staff, the Attorney General, and ABATE offer a variety of proposals that would result in a greater amount of the Midland plant proceeds being used for the benefit of Consumers, the utility, rather than CMS Energy, the holding company.

The Attorney General, through his witness, takes the position that the March 12, 1990 exchange of stock in CMS Midland and MEC Development for the CMS debenture did not represent an arm's-length transaction and was not one that Consumers would prudently accept if it were negotiating at arm's-length. He believes that the language of the Commission's orders is clear with respect to Consumers' obligation when it sells or transfers Midland plant assets, and he believes that in these special circumstances Consumers should not have unlimited freedom of action. In his view, the proposed sale and leaseback involves proceeds from the Midland plant, but he believes that there is not adequate information to analyze the proposed use of the proceeds. He asserts that without knowing all of the terms and conditions that might affect the liquidity and value of the notes created by the sale and leaseback, it is not possible to judge whether it is a proper use of the proceeds. The Attorney General concludes that all benefits from the Midland plant proceeds should flow to Consumers rather than the affiliates and subsidiaries of CMS Energy. The Attorney General recommends that

Consumers use the cash it can obtain from the MCV notes to pay down its bank debt, strengthen its balance sheet, and prepare to deal with the uncertainties that could weaken its balance sheet.

The Staff argues that Consumers acquired the Midland plant assets by heavy borrowing. The Staff asserts that it is only fair and logical that when the assets are removed from Consumers' books through a transfer to the MCV, the corresponding liabilities should also be discharged. Consumers does not propose to do that. In the Staff's view, the primary motivation of CMS Energy has been to afford itself the greatest flexibility to use the Midland plant proceeds, whether cash or otherwise, to pursue unregulated, mostly energy-related investments. The Staff submits that the underlying goals are to provide little or no cash to the utility, to remove as much cash from the utility as possible, and to bind Consumers to long-term power contracts and other obligations that will provide cash to CMS Energy for years to come.

The Staff's primary concern is to ensure Consumers' financial and business interests are not jeopardized by the plans of CMS Energy. The Staff is generally satisfied with Consumers' past performance in financial restructuring, but is concerned that recent actions indicate CMS Energy's intent to use utility resources and regulatory opportunities for its own interests rather than the combined good of CMS Energy and Consumers.

The Staff identified several financial uncertainties with which Consumers should be prepared to deal. Among those are the potential write-off of assets as a result of Case No. U-7830 Step 3B, in which the company seeks recovery of the abandoned Midland plant assets; the write-offs related to the Commission's approval of 3.77¢ per kwh rather than 4.15¢ per kwh and 17.5-year backloading rather than 10-year backloading in Case No. U-8871, in which the MCV sought approval of the capacity charges to be paid by Consumers; the potential inability of Consumers to sell additional MCV power; the write-off related to Plateau Resources; the potential inability of CMS Energy or Consumers to market the MCV notes at face value; the uncertainty of the rate increase that may result from Case No. U-7830 Step 3B, if any; the possible rate decrease resulting from the current electric rate case, Case No. U-9346; the uncertainty of proceeds from the sale of the Palisades generating plant; the uncertainty of how future gas prices may affect the MCV's profitability; and the general economic outlook for growth, inflation, and interest rates.

The Staff fears that if many or all of these uncertainties result in adverse effects on the utility, Consumers would be in a very weak financial position with its capital structure so highly leveraged. The Staff believes that Consumers is overcapitalized in relation to its rate base and needs to achieve a more balanced capital structure. The Staff recommends that CMS Energy be required to pay interest in cash on its debenture; that cash dividends from Consumers to CMS Energy be restricted to 30% of its net operating income until 1992 and 50% thereafter until Consumers has achieved at least a 40% common equity ratio; that Consumers use proceeds from the CMS Energy debenture and other cash to pay off the remaining $750 million of bank debt by December 31, 1992; that CMS Energy make additional principal prepayments equal to 30% of the net proceeds from the MCV notes when they are converted to cash; that Consumers maintain a normal construction budget of approximately $250 million per year; and that Consumers not sell or transfer other assets to its affiliates, or make loans, guarantee loans, or assume any financial obligations of its parent or affiliates without approval of the Commission.

ABATE argues that the term "proceeds" is not narrowly defined to mean cash only. ABATE would deny authority to exchange the MCV notes for a CMS debenture at this time. ABATE recommends that Consumers hold the Midland plant proceeds in short-term, non-speculative investments pending resolution of Cases Nos. U-7830 Step 3B and U-9346 and the final review of financial stabilization compliance. ABATE opposes Commission approval for use of the Midland plant proceeds in the sale and leaseback because there has been insufficient information and time to analyze that transaction.

II.

DISCUSSION

The Commission's March 29, 1985 financial stabilization order contained three types of conditions. There were conditions precedent to Commission authorization of the financial stabilization surcharges (e.g., the restructuring of bank debt and the commitment of Consumers' board to full compliance with the order and its conditions); there were on-going compliance conditions, violation of which would end the authorization of special rate relief (e.g., staying out of bankruptcy and no additional Midland plant expenditures without Commission approval); and there were conditions that required certain actions upon the occurrence of certain events (e.g., the stabilization revenue off-set to Consumers' recovery under Step 3B and Commission determination of the proper use of Midland plant proceeds).

As CMS Energy points out in its reply brief at page 5, some of the conditions contained in the 1985 stabilization order are substantive and some are procedural. Although the CMS Energy reply brief fails to note it, condition 11 contains both substantive and procedural elements. The failure of Consumers to comply with the procedural requirements of condition 11--the 45 day requirement, for example--could have resulted in the termination of financial stabilization rate relief. However, condition 11 also contains an explicit, unambiguous substantive provision: that the Commission will "issue an order specifying the proper use of [proceeds from Midland plant assets or litigation]." As the CMS Energy reply brief partially acknowledges at page 6, condition 11 gave the Commission the ability to ensure that Midland plant proceeds would be used to achieve the substantive goals of the financial stabilization order. But, contrary to CMS Energy's assertions, the substantive objectives and conditions of condition 11 have not yet been fully achieved and the rationale for condition 11 has not disappeared. Thus, the Commission finds that the obligations of condition 11 continue in effect.

The company obtained financial stabilization rate relief and its benefits by agreeing to abide by the conditions attached to it. Its Board of Directors specifically committed itself by official action at a May 1, 1985 board meeting to comply fully with the letter and spirit of the March 29, 1985 order,[2] including the condition 11 requirement to submit for Commission approval the planned disposition of proceeds from the Midland plant and related litigation. Consumers has never sought relief from condition 11, as it had with condition 5, and in fact has previously filed condition 11 applications related to the use of proceeds from the Midland plant. The Commission will not permit Consumers, now that the company has had the benefits of financial stabilization rate relief and claims that it is close to financial health, to disregard its obligations under condition 11 by using Midland plant proceeds in a manner that is inconsistent with what the company pledged to do to achieve the goals of financial stabilization.

As is clear from the Commission's 1985 orders, the special rate relief and conditions were designed to accomplish, among other things, at least three major goals:

---

[2] That commitment was renewed as recently as February 24, 1989 by action of Consumers' Board of Directors.

1. to stabilize Consumers' financial condition and cash flow in order to prevent bankruptcy, thereby protecting the long-term interests of ratepayers and shareholders;
2. to enable Consumers to recover its financial health, including a balanced capital structure, as quickly as possible; and
3. to minimize the extraordinary burden to Consumers' ratepayers in assisting with the company's recovery.

Various conditions were imposed to assure the accomplishment of all three of these goals, and the rate relief granted to Consumers was only one component.[3] Thus, the ending of that rate relief does not in and of itself assure the attainment of the letter and spirit of the financial stabilization goals. Some of the conditions, including condition 11, were not tied to on-going rate relief. They address the financial health of the company and the protection to be afforded to ratepayers and shareholders. Those conditions will remain effective until the events to which they are tied occur. In the case of condition 11, its application will end upon the resolution of the "proper use" of all Midland plant proceeds. Otherwise the Commission would not be able to minimize the extraordinary burden to ratepayers incurred in the financial stabilization of Consumers.

On February 21, 1990, Consumers witness Fisher testified that to his knowledge there were no plans to transfer the stock of CMS Midland and MEC Development from MGL and that any issuance of notes by the MCV was not likely to occur in the immediate future. However, when Consumers filed a motion on March 12, 1990 to end financial stabilization, it did not disclose that within a few hours of filing its motion, it would carry out the transactions that it now argues place the Midland plant proceeds beyond the Commission's jurisdiction.

---

[3] Consumers' electric rates are still not based on the cost of service and will not be until its pending rate case, Case No. U-9346, is concluded. Evidentiary hearings commence in September 1990.

Consumers and CMS Energy contend that once financial stabilization surcharges ended, the conditions of financial stabilization also ended. The Commission disagrees with that conclusion and notes that Consumers' and CMS Energy's position is not supported even by their own rationale. On March 12, 1990, when Consumers' subsidiaries transferred the Midland plant assets to the MCV for debt and equity interests and the subsidiaries were transferred to CMS Energy, the financial stabilization surcharges--and the financial stabilization conditions--were still in effect; Consumers had only filed a motion to terminate the special rate relief. The surcharges had not ended, and even if they had, that would not have terminated the conditions.

The Commission is also unable to agree with Consumers' view that "proceeds" only means cash. The position that proceeds only means cash is inconsistent with prior Commission orders and is wholly inconsistent with the intent of financial stabilization rate relief. Consumers' argument is particularly self-serving in this case because if Consumers does not have cash or a close equivalent from the assets transferred to the MCV, it is because Consumers transferred away the subsidiary holding the MCV notes that Consumers could have converted to cash. In exchange, it accepted a debenture that cannot be sold for 18 months, does not require cash interest payments for 3 years, and is to be paid over 15 years. Limiting the definition of proceeds to cash could have encouraged the company to avoid obtaining cash as it returned to financial health, just as Consumers has done in this situation. Such actions are not consistent with the letter or spirit of the March 29, 1985 order.

The Commission stated in its October 22, 1986 order in Case No. U-8431 that proceeds are not limited to cash, but noted that non-cash proceeds may require a different treatment than cash proceeds. With respect to the Midland nuclear fuel and other proceeds for which the company has previously received cash or a cash flow benefit, the Commission has required that financial stabilization rate relief be reduced correspondingly. That was consistent with the Step 3A purpose of giving the company additional cash flow to assist it in repaying debt and returning to financial health. The reduction in financial stabilization cash flow from ratepayers to reflect the cash flow obtained from Midland plant proceeds did not have the effect of enriching ratepayers or impoverishing the company. It simply reflected the Commission's finding that the company needed additional cash flow of $99 million per year for six years, whether that money came from ratepayers or Midland plant proceeds. Both were sources of cash available for repaying debt and returning the company to financial health. The Commission left open in earlier cases the possibility that non-cash proceeds, or even cash proceeds, should be used in ways other than reducing the amount of the rate increase. This case presents such a situation.

The Commission is aware of the language in the July 24, 1985 order on which CMS Energy relies to support an argument that proceeds only means cash. CMS Energy's argument illustrates how far current management has departed from the spirit of Step 3A. Rather than reading the Commission's orders as a whole, CMS Energy argues for a strained interpretation of selected language in Commission orders while ignoring clear language and the unambiguous intent of the Commission in granting financial stabilization rate relief. The argument also overlooks Consumers' prior acceptance of a broader definition as shown by its filing for approval of the use of non-cash proceeds. Consistent with the spirit of Step 3A, the company should be seeking ways to comply with rather than evade the letter and spirit of the financial stabilization order.

For purposes of condition 11, the Commission finds in this case that Midland plant proceeds include the debt and equity interests in the MCV that were transferred to CMS Midland and MEC Development. The Commission finds no merit in

Consumers' argument that the proceeds can only be what is directly held by Consumers. Consumers' use of other corporate entities to transfer the Midland plant assets does not place the proceeds beyond the Commission's review under condition 11. Because none of those entities existed when the Commission granted financial stabilization rate relief, the omission of references in condition 11 to subsidiaries and a holding company is hardly surprising. Still, it should be pointed out that condition 11 refers to Consumers' receipt of proceeds "directly or indirectly." Although the Commission makes no findings about the purposes or legal standing of the other corporations involved, the Commission finds that it need not recognize the technical formalities of Consumers' corporate organizational structure in implementing the purposes and requirements of financial stabilization rate relief. Mr. McCormick's testimony is instructive in this regard. In discussing the transfer of the MCV debt and equity to CMS Energy, he testified that the latest restructuring "would enable CMS [Energy] to move the debt and equity interests of the MCV out from under Consumers Power Company--out from under Midland Group Limited, I should say . . . ." (4 Tr.271.)

It is well beyond the letter and the spirit of Step 3A for the company to argue that by the simple expedient of creating subsidiaries, affiliates, and a holding company, it can evade any or all of the conditions of financial stabilization. Moreover, CMS Energy or its affiliates that now purport to hold the proceeds resulting from the transfer of Consumers' Midland plant assets to the MCV must be seen as successors in interest that accede to and inherit the related legal obligations of Consumers, including compliance with existing Commission orders; these lawful orders cannot be defeated by the mere device of creating separate corporations. Consumers agreed to the conditions of Step 3A, did not appeal those conditions, and has defended the conditions in the courts. Requiring the utility to adhere to its own agreement is not inequitable, and Consumers should not be absolved of the obligations merely by reorganizing itself into several corporations. In short, after having obtained the benefits of the Step 3A order from its ratepayers, Consumers may not escape any of the corresponding obligations that directly relate to those benefits.

The Commission does not see merit in Consumers' argument that because the Commission never asked CMS Energy to be bound by the conditions of financial stabilization rate relief, the corporation is not bound. To the contrary, in the context of financial stabilization, CMS Energy had a duty to request a release from the obligations and conditions of financial stabilization. Rather than undertake that action, CMS Energy pursued efforts to remove Midland plant proceeds from Consumers in disregard of the letter and spirit of the Step 3A order.

For purposes of condition 11 and financial stabilization, the Commission attaches no significance to the transfer by Consumers of Midland plant assets to CMS Midland and MEC Development or to the transfer of ownership of those corporations to MGL. Those transactions were essentially paper transfers to subsidiaries under the control of the utility. The Commission would only point out that if those transactions were viewed as creating proceeds, Consumers' failure to file an application for approval of the use of the proceeds would be a violation of condition 11. On the other hand, the transfer of the assets to the MCV on March 12, 1990 for debt and equity interests in the MCV did create proceeds within the meaning of condition 11. In order to use those proceeds, whether to purchase a CMS debenture or to engage in a sale and leaseback, Consumers must have Commission approval. As discussed below, the Commission will not approve the purchase of the debenture. Further, the Commission does not agree with the bare assertion that use of the MCV debt and equity interests in a sale and leaseback is not a use of the proceeds. In sum, for purposes of condition 11, the Commission considers the debt and equity interests received from the MCV in exchange for Midland plant assets as the proceeds held by Consumers that are subject to condition 11 of the 1985 financial stabilization order. Although the sale of the Midland plant assets to the MCV did not require Commission approval, use of those proceeds does require approval. Consumers' structuring of the transactions does not place the proceeds beyond the jurisdiction of the Commission.

At pages 50-51 of its brief, CMS Energy states with reference to the Midland plant proceeds that "Consumers' electric ratepayers have no claim even in the general equitable sense to CMS Energy's cash . . . ." At page 48 of its brief, CMS Energy complains that the proposals of the Staff, ABATE, and the Attorney General suggest that the Commission "order [CMS] Energy simply to donate a portion of the value of those assets to Consumers by unilaterally changing, to the detriment of [CMS] Energy, certain of the terms of the transactions which took place on March 12, 1990." And at page 50 of its brief, CMS Energy characterizes as "confiscation" efforts to have CMS Energy provide cash to its utility subsidiary in exchange for Consumers' investment in the transferred Midland plant assets. However, none of the parties in opposition to CMS Energy and Consumers has proposed that a refund be made with any Midland plant proceeds at this time or that the proceeds be given to Consumers' ratepayers. Thus, the fear expressed by CMS Energy in its brief that the proceeds would be "confiscated" and given to ratepayers is without basis. Further, CMS Energy's arguments clearly suggest that it has little interest, if any, in the obligation to assure the financial health of its utility subsidiary. This position is not consistent with the letter or spirit of the financial stabilization order and its conditions.

Contrary to the position of CMS Energy, the Commission finds that Midland plant proceeds should be used solely for the corporate purposes of Consumers. The original $1.5 billion investment in the useable Midland plant assets was on

Consumers' books prior to its corporate restructuring, and it has long been reflected in Consumers' capital structure. At this time, Consumers no longer has the $1.5 billion of Midland plant investment transferred to the MCV on its books, although the liabilities associated with the assets remain on Consumers' books. Granted, a present subsidiary of Consumers has been given a debenture by CMS Energy, but a subsidiary can easily be transferred to the parent company and the debenture is not equivalent to the MCV debt and equity interests. Thus, the Commission finds that the transactions among Consumers, CMS Energy, and their affiliates, described in this order, especially those occurring on March 12, 1990, constitute an attempt to evade the requirements of condition 11 of the Commission's Case No. U-7830 Step 3A financial stabilization order, in that Consumers has transferred $1.5 billion of booked assets (which are supported by its capital structure) and has not obtained adequate reimbursement for that transfer. Nor did Consumers file any application with the Commission under condition 11 in advance of the transactions to determine what should be done with the proceeds.

It is also clear that the various transactions between Consumers and its parent company, CMS Energy, and their affiliates were not effected through arm's-length bargaining. All of these corporations are headed by the same individuals and by essentially the same senior staff. The blurring of corporate identities is illustrated by Mr. McCormick's response when asked if he is the chief executive officer of CMS Midland: "I'm not sure of that. I'm not denying it but I'm really not sure." (Tr. 278.) While separate corporations can be given recognition for legitimate and lawful purposes, the corporations created by Consumers and its parent should not be permitted to work an evasion of the Commission's Step 3A orders, including condition 11, especially when the evasion results in a detriment to the utility and its ratepayers. Moreover, the Commission is certain that if no corporate reorganization of Consumers had taken place, and if arm's-length bargaining had occurred, it is unlikely that Consumers would have accepted the debenture that has been provided in this case to its subsidiary. The Commission finds that the Midland plant proceeds must be returned to Consumers and not to any subsidiary of Consumers or CMS Energy. Further, Consumers must use the proceeds for lawful corporate purposes of the utility that are consistent with the goals of the 1985 financial stabilization order.

The question that remains is what corporate purposes are consistent with the goals of the Commission's March 29, 1985 order. The position of Consumers and CMS Energy is that they should be permitted to do as they please with the proceeds. In support of this position, they argue that the Midland plant assets transferred to the MCV were removed from Case No. U-7830 Step 3B in which the company seeks to recover for the abandoned Midland plant assets. Consumers argues that with the removal of those assets from Step 3B, its ratepayers were not at risk for a rate increase to pay for the assets and, therefore, they should not receive the benefit of those assets; in other words, its shareholders bore the risk and should reap the benefits. In short, Consumers asks the Commission to find that when the Commission permitted the company to resume construction of the Midland plant as a natural gas-fired cogeneration facility, the Commission's action also permitted Consumers to transfer away the only useful Midland plant assets with no expectation or requirement that Consumers use those assets or the proceeds that could be obtained for them to assist its return to financial health. That position is unfounded. Among other things, it overlooks the fact that Consumers transferred the usable assets but did not transfer the liabilities, which still remain on Consumers' books.

As the Commission has made clear in prior orders, including the August 23, 1988 order in Cases Nos. U-8630 and U-8713, which determined the use of some Midland plant proceeds, the distinction between jurisdictional and non-jurisdictional activities is not controlling in the context of financial stabilization. The Commission's March 29, 1985 order required Consumers to use all of its assets, and those of its subsidiaries, regulated or not, to assist its return to financial health. The Commission also rejects as erroneous the argument that the grant of relief from condition 5 carried an implied release of the MCV proceeds from condition 11. Such an argument is an unconvincing effort to change the meaning of a Commission order that is clear on its face. In answer to Consumers' and CMS Energy's rhetorical questions about why they would have pursued the MCV project if their shareholders could not benefit directly after bearing the risk of the project, the Commission states that the letter and spirit of financial stabilization required them to use all of their abilities and assets to return the utility to financial health. Furthermore, it is clear that the MCV project provides CMS Energy the opportunity to recover Consumers' original investment plus profit from the statutorily-assured sale of power to Consumers at the utility's avoided cost. Moreover, the stronger and more financially healthy utility resulting from the realization of Midland plant proceeds helps shareholders, as well as serves the public interest, because the utility will be better able to meet its service obligations to the public, while also providing appropriate dividends to its shareholders, including its parent company, CMS Energy, subject to present limitations.

Consumers appears to believe that its proposed use of the proceeds--that is, diverting them entirely to the immediate use of CMS Energy with the potential for those proceeds to be returned to a Consumers subsidiary as principal and interest payments on the CMS Energy debenture at a later time--will sufficiently serve the needs of Consumers as it completes its return to financial health. The Commission neither concurs with this assessment nor is reassured by the company's promises and commitments that this arrangement will be satisfactory. The company's assessment is based upon optimistic assumptions, and it leaves little room for adverse contingencies. The proposal provides little cash for the utility and limited opportunities to raise cash from the debenture.

The CMS Energy debenture is a long-term promise to pay, which is unsecured and essentially non-liquid and non-marketable. It is subject to all of the business risks that CMS Energy will incur in speculative, non-regulated ventures, which makes it far more risky and speculative than the MCV debt and equity, which are supported by a healthy cogeneration capacity rate and a stream of revenues assured by the framework of state and federal law governing cogeneration. Further, there is only a speculative cash flow benefit to Consumers from the debenture. First, it is held by MGL, currently a subsidiary of Consumers, which could easily be transferred to the parent company under the parent company's direction, if and when any cash flow benefits are payable. Second, the debenture does not provide for interest payments in cash during the early years of the instrument, and cash payments in later years could easily be deferred by the parent company's dictating changes in the terms of the debenture. In this regard, CMS Energy controls Consumers and its affiliates, because it wholly owns the subsidiaries. The debenture also has numerous restrictive provisions that make it less desirable. Finally, the payments to be made under the debenture by CMS Energy must be based in large part upon the speculative returns from CMS Energy's new ventures or, alternatively, upon future dividends from Consumers, the cash-providing utility subsidiary. In the latter instance, if Consumers is required to pay increased dividends to CMS Energy for purposes of meeting the debenture requirements, Consumers' ratepayers could be called upon to provide additional revenues in effect to meet CMS Energy's promise to pay under its debenture. All of these factors indicate that the debenture is of far less value to Consumers than the MCV debt and equity obtained directly from the transfer of Midland plant assets to the MCV.

The "put" option in the debenture provides a good illustration of the limited value of this asset to Consumers. Upon the occurrence of specified conditions, Consumers' subsidiary, MGL, can require CMS Energy to pay off the debenture. If CMS Energy has exercised the payment in kind interest provision of the debenture, at the end of three years it will owe $2.1 billion on the debenture. At that time, if CMS Energy is not doing well financially, it is unclear whether or how CMS Energy could come up with the money to pay off the debenture. In short, the put option is of dubious benefit to Consumers' subsidiary. The value of the benefit is further reduced when one remembers that CMS Energy could "renegotiate" the terms of the debenture with the wholly-owned subsidiary, MGL, of its wholly-owned subsidiary, Consumers, or get certain obligations forgiven altogether.

The negotiations that led up to issuance of the debenture are also instructive. Morgan Stanley & Co., Incorporated represented Consumers and Mr. Fryling represented CMS Energy. Again, Mr. Fryling is Executive Vice President and Chief Financial Officer of both Consumers and CMS Energy. And it was Morgan Stanley that provided the "fairness opinion" regarding whether the value of the CMS debenture is at least equal to the value of the stock of MEC Development and CMS Midland--that is, the value of the proceeds transferred to those subsidiaries from the Midland plant assets. It should be noted, moreover, that the fairness opinion states that Morgan Stanley "assumed and relied without independent verification upon the accuracy and completeness of all financial and other information . . . reviewed." (Emphasis added.) The Commission, however, remains unconvinced about the fairness of the transaction and points out that the asserted fairness of the transaction says nothing about whether it is consistent with the conditions and goals of financial stabilization.

Because Consumers is far and away the largest source of profit for CMS Energy, the ability of CMS Energy to repay the debenture, with interest, depends in large part upon the earnings of Consumers. If CMS Energy were to invest $1.2 billion in unregulated activities that are successful, it would have a source of cash to repay the principal and interest on the debenture. However, the Commission recognizes that substantial risks are involved in that course of action. Among the questions left unanswered are:

1. What if CMS Energy's diversification investments are unsuccessful?
2. What if the MCV is not successful in operating its cogeneration plant cost-effectively for 35 years?
3. What if there is an economic downturn or reduction in electricity sales?
4. What if interest rates and inflation increase substantially?
5. What if, as a result of pending cases and subsequent appeals, Consumers is required to write off $1 billion or more against its common equity?
6. What if extensive expenditures are required to remedy the effects of reduced operation and maintenance and construction budgets during the past five years?

It may be that CMS Energy is correct in assuming that its plan will permit it to weather some or all of these contingencies. However, the Commission finds that it is unreasonable to take that risk at this time, especially when Consumers is just emerging from a financial emergency and it has within its grasp the opportunity to do much to restore itself to full financial health and to prepare to respond effectively to adverse contingencies. On the basis of the findings noted above, the Commission concludes that the investment of Midland plant proceeds in the CMS Energy debenture by Consumers' subsidiary does not reasonably aid the utility in returning to financial health and therefore is not a proper use of Midland plant proceeds under condition 11.

The Commission has no interest in regulating CMS Energy or any of its unregulated subsidiaries and affiliates. The Commission's concern in this proceeding is to assure that ratepayers obtain the benefits for which they paid an extraordinary rate increase and to protect the financial health of a regulated utility. It is not in the best interest of ratepayers--or any of the investors in Consumers and CMS Energy, for that matter--to risk the utility's financial health or postpone full financial recovery. The utility must take the opportunity that luck and hard work have placed before it and strengthen its financial condition in order to prepare for the future. Five years ago the management of Consumers committed itself to complying with the letter and the spirit of financial stabilization rate relief, including condition 11. The Commission expects no less today.

The proper use of the Midland plant proceeds is to secure Consumers' financial health, which was the basic goal of the financial stabilization order. To further that goal, the order required the repayment of $1.9 billion in bank debt and other obligations and a commitment to work toward and maintain a balanced capital structure. The order did not define financial health and, in particular, did not define it as having only two components--repayment of $1.9 billion of obligations and attainment of a balanced capital structure. The broader goal is important when the company continues to carry $750 million of bank debt and faces the risk of substantial write-offs against common equity. Consumers committed itself to the attainment of financial health before it received financial stabilization rate relief, and it must now use the Midland plant proceeds in a manner that is consistent with that goal and commitment. Therefore, Consumers may use the proceeds as it determines best so long as the use strengthens the utility's financial health. Consumers may not use the proceeds for things that do not strengthen its financial situation, such as making extraordinary dividend payments to CMS Energy or making loans, guaranteeing loans, or assuming financial obligations of its parent, affiliates, or subsidiaries.

Based on the record, it appears that the company should use a portion of the Midland plant proceeds to repay more of its bank debt. As the company's prior management learned, bank debt that must be refinanced within a few years can be riskier than other long-term debt. That was the reason the March 29, 1985 order required restructuring and repayment of $1.2 billion of bank-related debt (in addition to $.7 billion of other obligations). The Commission has previously approved Consumers' proposals to defer payment on the restructured bank debt of approximately $750 million because deferral permitted Consumers to pay off more expensive debt and obligations first. It also seemed likely that as its credit improved, it would be better able to discharge its other debt obligations and refundings at advantageous rates. It should do so now in a reasonable manner.

CMS Energy argues that repayment of the bank debt at this time will lead to a higher-cost capital structure. In the short-run, that may be true, just as a large common equity write-off yields a short-run reduction in the weighted cost of capital. However, the company's argument assumes that repayment of bank debt will not lead to an improved credit rating and a reduction in Consumers' cost of debt. It also ignores the fact that interest on debt is a fixed obligation of the utility that must be paid when due, unlike the dividends on common equity, which can be deferred. Thus, CMS Energy's approach would increase Consumers' long-term financial risk in the hope of a short-term reduction in the cost of capital. The Commission's concern is the long-term financial health of Consumers, not the pursuit of the least expensive cost of capital in the short run.

Consumers should also take steps to assure a balanced capital structure in light of the potential write-offs and other risks that face the company in the near future. Those write-offs could reduce the common equity portion of the capital structure to less than 30%, far short of the 40% that CMS Energy agrees is appropriate. Consumers says that "it is hardly for the Commission, after causing an equity writedown, to then expropriate nonjurisdictional funds in order to dictate to Consumers' management how to remedy the problem which has been created for it." (Consumers' brief, p. 50.) It is a meaningless exercise in finger pointing for Consumers to argue that equity write-offs are largely the responsibility of the Commission. Proper regulation does not require the Commission to approve a utility's decisions when disapproval would have an adverse effect on the company's balance sheet. Nor does the Commission have the final say on those matters. The Commission now has before it, and has previously had before it, a number of cases that, if not ultimately resolved as Consumers hopes, will result in write-offs. It may also be true that regardless of the Commission's decisions, once the appellate process is completed, there will still be write-offs, perhaps larger ones than result from the Commission's orders. Consumers' managers must simply accept that reality and prepare to address it in a way that leaves the company in good financial health. Through wise use of the Midland plant proceeds, Consumers has the opportunity to reduce its total long-term debt obligation, to improve its capital structure, to improve its credit rating above the lowest investment grade, to improve the company's ability to borrow for future needs, to refinance existing higher-cost debt, to improve the company's cash flow, and to bring its capitalization and utility rate base into balance. In light of its commitments under financial stabilization, it is necessary for Consumers' management to select a course of action consistent with these goals.

Having found that the proceeds should be held by Consumers for the benefit of the utility, the Commission concludes that the sale and leaseback can go forward to the extent that it is not inconsistent with the purposes described above. As explained on the record, it appears that the currently negotiated sale and leaseback will result in CMS Midland's exchanging its current equity interest for some cash and a smaller equity interest and another CMS Energy subsidiary's obtaining an equity interest. It will also result in MEC Development's exchanging the notes and potential notes from the MCV for notes from Midland Funding. Neither this order nor the Commission's prior orders should be viewed as barring the sale and leaseback, provided the equity, notes, cash, and other proceeds resulting from these transactions are to be provided to and held by Consumers--not a subsidiary and not CMS Energy or its subsidiaries--and will be at least equal in value, liquidity, and marketability to the equity and debt interests currently held by CMS Midland and MEC Development, and will be available for Consumers' use as provided in this order.

In conclusion, it seems appropriate to make some general observations about the actions of Consumers' management. The current managers appear to have forgotten the cries of financial disaster by utility management in 1984 and 1985. In response, the Commission granted extraordinary rate relief, which required an extraordinary sacrifice by Consumers' ratepayers. The Commission acted in what it found to be the best interests of the State of Michigan and Consumers' ratepayers, shareholders, and creditors. The Commission believed that, in the long run, the public interest would be best served if Consumers were granted the extraordinary rate relief. The Commission placed conditions on that rate relief to enable Consumers to return to financial health and remain there without another rescue by the Commission and ratepayers. In the spirit of the extraordinary rate increase, the Commission expected that Consumers would use all of its management skills, self-help, and financial and business opportunities to strengthen its utility operations and financial position, and Consumers' management provided an unqualified commitment to comply with the letter and the spirit of the conditions attached to the extraordinary Step 3A rate relief.

The testimony of Consumers' and CMS Energy's officers and the proposal offered by Mr. Fryling during rebuttal illustrate how far the current management of the company has moved from the spirit of Step 3A. Instead of using its resources to return the company to financial health, the company's management has pursued all conceivable legal and regulatory avenues to separate the benefits of improved financial health from the utility and to transfer them to the parent holding company, where they can be used in whatever way those managers see fit, even though Consumers has not yet achieved financial health and faces many near-term uncertainties that prudent managers would not ignore. What has developed is a concerted effort to prevent the utility from obtaining cash to meet its obligations and prepare for contingencies and, instead, to use the cash from Midland plant assets for non-utility enterprises. The Commission would not be carrying out its appropriate regulatory responsibilities if it quietly acquiesces to this course of action.

III.

REMAINING ISSUES

On April 9, 1990, ABATE filed a motion for clarification of the April 6, 1990 order that commenced this proceeding. ABATE stated that the Commission's order contains a definition of proceeds with which ABATE agrees. ABATE was concerned however that on page 3 of the order the Commission stated that Consumers filed under protest its application proposing a use for the proceeds, as required by condition 11 of the March 29, 1985 order. ABATE argued that Consumers' application did not propose how proceeds should be used. ABATE expressed its concern that that sentence in the Commission's order would be taken out of context by Consumers to argue that the Commission had found that the application met the requirements of condition 11.

It does not appear to the Commission that ABATE's concern is borne out by the record. The request for clarification of the order is therefore denied.

On April 13, 1990, ABATE filed a motion to require Consumers to file a proper condition 11 application. ABATE alleged that Consumers had not addressed how it intends to use the proceeds from the sale of Midland plant assets and is attempting to bypass the authority of the Commission by trying to have the Circuit Court validate the uses to which Consumers intends to put the proceeds. ABATE asserted that the one proper subject of this proceeding is the use of the equity interests and notes received by CMS Midland and MEC Development from the sale of Midland plant assets and the use to which they may be put. ABATE alleged that although the equity interests and notes are to be used in a sale and leaseback, Consumers did not address that use in its application. ABATE concluded that the sale and leaseback involves CMS Energy, Consumers, CMS Enterprises, and their subsidiaries and affiliates, including the MCV, and as such is within the scope of the Commission's order.

There may be merit to ABATE's argument that Consumers' condition 11 application did not fully comply with the Commission's order. Still, the record addresses the sale and leaseback, and is complete enough for the Commission to decide this case.

On April 18, 1990, the MCV filed a motion for clarification of the March 27 and April 6, 1990 orders. The MCV stated that the March 27, 1990 order apparently enjoins CMS Energy, CMS Enterprises, Consumers, and unnamed subsidiaries and affiliates from carrying out the actions described in the March 14, 1990 temporary restraining order. The MCV stated that it is unclear whether the March 27, 1990 order was intended by the Commission to conflict with the terms of the March 16, 1990 amended temporary restraining order or whether the

March 27, 1990 order was intended by the Commission to preclude the completion of the sale and leaseback. The MCV asserted that the uncertainty created by the March 27, 1990 order will by itself prevent completion of the sale and leaseback. The MCV requested the Commission to clarify the March 27 and April 6, 1990 orders to clearly state that the Commission did not and does not intend to either undo the initial phase of the sale and leaseback, which closed on March 16, 1990, or to prevent the completion of the sale and leaseback. The MCV suggested that the Commission order state that the March 27 order was not intended to and does not preclude the MCV or any other entity from entering into one or more sale and leaseback arrangements with respect to the MCV facility and, further, that the March 27 order does not restrict any entity from taking actions necessary to effectuate the sale and leaseback.

On April 23, 1990, the MCV filed a supplement to its motion for clarification with a copy of the deposition by Mr. Lasher with additional information concerning the sale and leaseback and an affidavit from William B. Gordon, who is director of Salomon Brothers, Inc., concerning the negotiations for the sale and leaseback.

On May 14, 1990, the Staff, ABATE, Consumers, and CMS Energy and CMS Enterprises et al. filed responses to the MCV's motion. The Staff stated that the MCV seeks to have the Commission render a decision regarding the proceeds that Consumers has received for the transfer of Midland plant assets prior to the ruling to be issued by May 21, 1990 (now May 23, 1990). The Staff noted that any problems that the MCV alleges it has with respect to time constraints were caused by Consumers' failure to timely file a condition 11 application. The Staff suggests that to rule on the MCV's motion at this time would prejudge the issues that are under consideration.

ABATE stated that the use of Midland plant proceeds in the sale and leaseback is currently at issue before the Commission and there is no need for clarification. ABATE views the MCV's request as perhaps an attempt to obtain a prejudgment on the appropriate use of proceeds or an effort to have the Commission make a decision before the record is complete. ABATE also pointed out that unless the sale and leaseback involves the unauthorized use of Midland plant proceeds, it should be unaffected.

Consumers supported the MCV's motion and urged the Commission to grant the relief. CMS Energy and CMS Enterprises also concurred in the relief requested by the MCV.

As discussed above, the Commission does not intend to prohibit a sale and leaseback from occurring in a manner consistent with this order; nor does it intend to undo the initial phase of the sale and leaseback. The MCV, Consumers, CMS Midland, CMS Enterprises, and their subsidiaries and affiliates are therefore free to carry out a sale and leaseback that is consistent with this order.

On May 9, 1990, ABATE filed a motion for sanctions against Consumers for concealment of video-taped evidence. ABATE stated that it requested a video tape of a presentation by Mr. McCormick, Mr. Fryling, and S. Kinnie Smith before the New York Society of Security Analysts, and a subpoena duces tecum was issued by the Commission's Executive Secretary. In response to that subpoena, Consumers produced a seven-minute video tape that did not contain the presentations of the three nor the question and answer session that followed their presentation. ABATE requested sanctions for Consumers' willful and knowing defiance of the subpoena.

On May 16, 1990, Consumers filed a response in which it argued that ABATE received exactly what it asked for. Consumers also stated that the video tape that ABATE apparently wants is available from the New York Society of Security Analysts for a $6 fee.

Under the circumstances, the Commission does not find sanctions would be appropriate. In any event, by court order, the Commission must issue an order by May 23, 1990.

On April 30, 1990, ABATE filed a motion for sanctions against Consumers and CMS Energy because, by the date ABATE's direct testimony was due, Consumers had failed to answer approximately 65 of ABATE's discovery requests.

On May 4, 1990, Consumers filed a response arguing that ABATE attempted to overwhelm the company with burdensome discovery. Consumers argued that it responded to virtually all of ABATE's requests before the record opened, with the exception of one question that was answered in the prefiled testimony of Mr. McCormick. On May 14, 1990, CMS Energy filed a response arguing that there is no basis for sanctions against it.

In the circumstances of this case, the Commission will not grant ABATE's request. The record contains adequate information for the Commission to decide the issues, and the Commission has no basis for judging how the record would be different if greater time had been permitted for the parties to prepare. The Commission must issue a decision, and will do so today based on the record before it.

On April 27, 1990, Consumers filed a motion to compel ABATE's response to discovery. Consumers stated that it served discovery on ABATE on April 11, 1990, and ABATE filed a response refusing to answer or avoiding every discovery request.

On May 9, 1990, ABATE filed a response. ABATE asserted that it appropriately and in good faith responded and objected to each of Consumers' requests. ABATE further asserted that Consumers had not asserted that it had good cause to request any of the information. ABATE asserted that the discovery relates to the sale and leaseback of MCV pollution control equipment and seeks to discover who, other than CMS and its affiliates, is participating.

The record is closed and the Commission must make a decision based on that record. It is apparent that there were difficulties in discovery. This proceeding, conducted in a short time frame, does not provide an appropriate opportunity for the Commission to remedy the problem. As already noted, the record is adequate to decide the issues before the Commission.

On May 17, 1990, the MCV moved to strike a portion of ABATE's reply brief that suggests conditions that should be applied to the proposed sale and leaseback. The MCV objects to ABATE's withholding of its position until no further opportunity to reply is available. On May 18, 1990, CMS Energy filed a concurrence in the MCV's motion.

On May 22, 1990, ABATE filed a response to the MCV's motion, arguing that Consumers failed to place the sale and leaseback before the Commission for approval but, because the record addressed it, ABATE suggested points that the Commission should consider if it is to approve the transaction. It also argued that its suggestions should not surprise anyone and are based on the record.

The Commission does not agree that ABATE was required to list its points at an earlier time. This case was conducted under an expedited schedule, and Consumers failed to raise the sale and leaseback in its application. In addition, ABATE's points are not unrelated to the record. The Commission therefore denies the motion to strike that portion of ABATE's reply brief.

On May 18, 1990, ABATE filed a motion to supplement the record. Because the Commission must issue its order today, there is no time for presentation of witnesses or cross-examination and rebuttal related to the evidence ABATE now offers. Regardless of the reasons for offering the evidence now and not earlier, the Commission must issue its order on the existing record, which it finds sufficient.

The Commission FINDS that:

a. Jurisdiction is pursuant to 1909 PA 300, as amended, MCL 462.2 et seq., including sections 4, 10, 22, 28, 32, and 44; 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 144, as amended, MCL 460.301 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; the Commission's Rules of Practice and Procedure, 1979 Administrative Code, R 460.11 et seq.; and the Commission's orders in Case No. U-7830 Step 3A.

b. The proceeds from the disposition of the Midland plant assets to the MCV are subject to Condition 11.

c. The proceeds include all cash and non-cash consideration exchanged for Consumers' $1.5 billion in Midland plant assets that were transferred to the MCV, including but not limited to the equity and debt interests in the MCV transferred to CMS Midland and MEC Development.

d. These proceeds should be returned to Consumers, should be held solely by it, and should be used solely for lawful corporate purposes related to securing the financial health of the utility.

THEREFORE IT IS ORDERED that:

A. The proceeds from the Midland plant assets shall be returned to Consumers Power Company--not a subsidiary and not CMS Energy Corporation or its subsidiaries--and it shall hold and use the proceeds solely in accordance with the terms of this order.

B. Consumers Power Company and its officers and directors shall take all necessary steps to effectuate this order and shall report to the Commission within 20 days all actions they have taken and will take to comply with this order.

The Commission specifically reserves jurisdiction of the matters herein contained and the authority to issue such further order or orders as the facts and circumstances may require.

Any party desiring to appeal this order must perfect an appeal to the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26.

MICHIGAN PUBLIC SERVICE COMMISSION

/s/ William E. Long
Chairperson

(SEAL)

/s/ Steven M. Fetter
Commissioner

/s/ Ronald E. Russell
Commissioner

By the Commission and pursuant to its action of May 23, 1990.

/s/ Dorothy Wideman
Its Executive Secretary

444 Market Street, Suite 1900
San Francisco, CA 94106
415/291-6410
Fax 415/291-6498

Mason Willrich
President and Chief
Executive Officer

PG&E
Enterprises

March 27, 1991

Mr. William Conway
Chief Counsel
Subcommittee of Water and Power
364 Dirksen
Washington, D.C. 20510

Dear Bill:

Pursuant to your request, attached is a draft of legislation which I have prepared aimed at establishing a Consultative Commission on North American Energy and Environment. These provisions could be incorporated into the proposed National Energy Security Act which the Senate Energy Committee is now considering or adopted in the form of a separate Senate and/or House resolution.

Also attached is a copy of the agreed statement developed by the trinational private group sponsored by the North American Institute of which I am a member. The draft legislation draws heavily from the agreed statement, but I have also made certain modifications which I believe should enhance its acceptability to the U.S. government, while not diminishing its attractiveness to Canada and Mexico.

Please let me know how I can be of further assistance in this matter.

Sincerely yours,

Mason

MW/slp
Enclosures

THE ■ ■ NORTH ■ ■ AMERICAN ■ ■ INSTITUTE

EMBARGOED EMBARGOED EMBARGOED

Meeting on Energy and Environment

Sponsored By

The North American Institute (NAMI)

Oaxtepec, Mexico

AGREED STATEMENT OF PARTICIPANTS

Our discussions were based on mutual recognition of the growing economic and social interdependence among our three North American countries and of the need to foster continued development of mutually beneficial relations as a matter of high priority.

We discussed the energy and environmental outlooks of Canada, Mexico and the United States, and the links between energy and environmental issues and the issue of sustainable economic and social development for each of our countries and for the North American region as a whole.

We concluded that each of our governments, in formulating its national energy and environmental policies, should consult regularly with the other governments on a trinational basis.

To that end, we recommend that the Heads of Government of Canada, Mexico and the United States establish a Trinational Consultative Commission on North American Energy and Environment.

The following is a summary of our conclusions and recommendations

128 GRANT AVENUE, SUITE 221, SANTA FE, NEW MEXICO USA 87501 (505) 982 3657

CONCLUSIONS

- Energy plays a vital pervasive role in the economic and social development of Canada, Mexico and the United States. Insufficient energy supplies would severely constrain future opportunities for development and growth in each of the countries. Fortunately, the North American Continent is richly endowed with energy resources: oil, gas, coal, uranium, and renewable.

- The development, production and consumption of energy are major sources of environmental pollution. Urban smog, acid rain, and global warming are major consequences of hydro-carbon combustion, while long-lived radioactive waste results from nuclear fission. The environmental consequences of energy-related activities are not confined within national boundaries, but are regional and global concerns.

- The energy sectors of the economies of Canada, Mexico and the United States are interdependent. In particular, the United States imports large amounts of oil from Mexico, and large amounts of oil and natural gas and significant amounts of electricity from Canada. Inefficiencies in the energy performance of the United States, leading to excessive reliance on imported oil are an increasing concern of Canada and Mexico. The continued availability of oil exports from Mexico and oil and natural gas exports from Canada, among others, will be a continuing concern of the United States.

- The countries of North America should focus future development of their energy infrastructures on ways which are sustainable over the long-term in light of existing and emerging environmental constraints. To accomplish this:

    - Energy prices should reflect full costs, including costs of consequential damage to the environment. Gaps between prices based on full costs and current market prices should be closed through charging user fees or consumption taxes, with the proceeds used to support desirable technology development and to provide transition adjustments for adversely affected industries, as well as to clean up past environmental damage.

– Energy markets should be open, subject to each country providing for its energy supplies from domestic production. Competitive market forces should be used as a primary means to assure that energy resources are developed and used in timely and efficient ways.

– Measures to enhance efficiency of energy use and conserve energy resources, and the development of advanced technologies to make use of solar, nuclear and other non-fossil energy resources should receive a high priority.

– Canada and the United States, as industrially advanced countries, can afford to allocate more resources to environmental protection than Mexico, for which economic development remains the more immediate imperative. Nevertheless, the environmental problems Mexico faces are enormous. If the three countries which share the North American continent can find collaborative solutions for environmental problems of the North American region, their success could serve as a model for development of solutions to wider North-South issues regarding environment and development.

– Canada, Mexico and the United States should consult regularly on a trinational basis, regarding the formulation and implementation of their respective national policies on energy development and use environmental protection. This conclusion is based not only on the intrinsic requirements for effective energy and environmental policies, but also on our geographical proximity on a shared continent and the growing interdependence of our economies as a whole.

RECOMMENDATION

We recommend that the Heads of Government of Canada, Mexico and the United States establish a trinational Consultative Commission on North American Energy and Environment, in order to assess common problems and seek collaborative solutions. The Commission would have the following purposes, composition and duration.

Purposes: The purposes of the Consultative Commission would be:

- **To evaluate from the viewpoint of the North American region, the energy and environmental situations, trends and policies of Canada, Mexico and the United States.**
- To recommend to the governments of the three principal North American countries actions, policies and institutional arrangements that will enhance cooperation and policy coordination among them in their future development and use of energy resources and technologies, and in their future development and implementation of measures to protect the environment of the North American Continent.

Composition: The Consultative Commission would be composed as follows:

- The heads of the respective energy ministries or departments and the heads of the respective environmental ministries or departments of the governments of the three countries.
- The chairmen of the parliamentary or congressional committees with leading legislative responsibilities for energy and environmental matters.
- A limited number of additional members appointed by the heads of government to represent their respective energy industries and non-governmental environmental organizations.

- A small trinational secretariat of experts secunded temporarily by the three governments.

Duration: The Commission would be established for a period of five years. The existence of the Commission could be continued for additional five-year periods upon the affirmative decision of the three governments. After the initial five-year period, the three governments would consider whether additional countries should be invited to join the Commission.

THE NORTH AMERICAN INSTITUTE

PARTICIPANTS FOR NAMI DECEMBER MEETING

December 8, 1989

Canadian Participants

Sen. Jacob Austin
Senate of Canada

Dr. David Brooks
International Development Research Centre

Mr. David Crane
Toronto Star

Dr. Rodney Dobell
Institute for Research on Public Policy

Mr. Andre Saumier
Saumier, Morrisson & Associates

Hon. Mitchell Sharp
Former Sec. of State for External Affairs

Dr. Ian Stewart
Advisor, Consultant

U.S. Participants

Mr. Mason Willrich
PG&E Enterprises

Mr. Tony Day
Los Angeles Times

Prof. Alan Manne
Stanford University

Hon. Charles Robinson
Former Dep'y Secretary of State

Thomas Strickland
Brownstein, Hyatt, Farber & Madden

Dr. Daniel Yergin
Cambridge Energy Resource Associates

Mr. Victor Palmieri
The Palmieri Company
ODC Chairman

Mexican Participants

Lic. Jesus Silva-Herzog
Centro de Estudios Monetarios Latino-americanos

Ing. Francisco J. Garza
Vitro Industrias Básicas

Ing. Claudio X. Gonzales
Kimberley-Clark

Lic. Jesus Reyes Heroles
Coordinator of Advisors for Secretary of Foreign Relations

Lic. Adrian Lajous
Political Commentator

Dr. Adrian Lajous, Jr.
Deputy Director, Planning PEMEX

Dr. Lorenzo Mayer
Colegio de Mexico

Dr. Carlos Rico
Colegio de Mexico

Prof. Juan Lindau
Observer
The Colorado College

Prof. John Wirth
Moderator
Stanford University

Dr. Elizabeth Sherwood
Rapporteur

Susan C. Herter
President, NAMI

12/6/89

128 GRANT AVENUE, SUITE 221, SANTA FE, NEW MEXICO USA 87501 (505) 982 3657

DRAFT LEGISLATION TO ESTABLISH A CONSULTATIVE COMMISSION ON NORTH AMERICAN ENERGY AND ENVIRONMENT

WHEREAS:

1. There is growing economic interdependence among Canada, Mexico and the United States of America, which constitute the three largest North American countries;

2. There are multiple links between energy and environmental issues and the larger issue of sustainable economic development for each of our countries and for the North American region as a whole;

3. The countries of the North American region should focus future development of their energy infrastructures on ways which are sustainable over the long-term in light of existing and emerging environmental constraints;

4. The coordination of respective national energy and environmental policies of the governments of Canada, Mexico and the United States could be substantially improved through regular trinational consultation.

FINDINGS

1. Energy plays a vital pervasive role in the economic development of Canada, Mexico and the United States.

2. The development, production and consumption of energy have major impacts on environmental quality. The environmental consequences of energy-related activities are not confined within national boundaries, but are regional and global concerns.

3. The North American Continent is richly endowed with energy resources: oil, gas, coal, uranium, and renewable. Insufficient energy supplies would severely constrain future opportunities for development and growth in each of the countries.

4. The energy sectors of the economies of Canada, Mexico and the United States are interdependent. In particular, the United States imports large amounts of oil from Mexico, and large amounts of oil and natural gas and significant amounts of electricity from Canada.

5. The energy markets of the North American countries are linked with those in other countries of the Western Hemisphere and in other regions into global markets.

THEREFORE:

1. The President is authorized and directed to seek through negotiations with the governments of Canada and Mexico to conclude appropriate arrangements for the establishment of a trinational Consultative Commission on North American Energy and Environment.

2. In the conduct of negotiations, the President shall seek agreement on the following matters, among others, related to the Commission:

(a) Purposes. The purposes of the Consultative Commission would be:

i) To evaluate from the viewpoint of the North American region, the energy and environmental situations, trends and policies of Canada, Mexico and the United States.

ii) To recommend to the governments of the three participating North American countries actions, policies and institutional arrangements that will enhance cooperation and policy coordination among them in their future development and use of energy resources and technologies, and in their future development and implementation of measures to protect the environment of the North American Continent.

iii) To recommend to the governments of the three participating North American countries actions and policies that will enhance energy and environmental cooperation and coordination among the countries of the Western Hemisphere.

(b) Composition: The Consultative Commission would be composed of:

i) The heads of the respective energy ministries or departments and the heads of the respective environmental ministries or departments of the governments of the three countries.

ii) The chairmen of the parliamentary or congressional committees with leading legislative responsibilities for energy and environmental matters.

iii) A limited number of additional members appointed by the heads of government with experience in their respective energy industries and non-governmental environmental and consumer organizations.

iv) A small trinational secretariat of experts secunded by the three governments.

(c) Duration: The Commission would be established for a period of five years. The existence of the Commission could be continued for additional five-year periods upon the affirmative decision of the three governments. After the initial five-year period, the three governments would consider whether additional countries should be invited to join the commission.

3. The President is requested within one year of the enactment of this legislation to report to the Congress on progress in the negotiations and establishment of a Consultative Commission on North American Energy and Environment.

COMMENTS OF THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES (NASUCA) REGARDING TITLE XV OF S. 341 PUBLIC UTILITY HOLDING COMPANY ACT REFORM

CONGRESS OF THE UNITED STATES

SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

March 20, 1991

Submitted by:

Billy Jack Gregg
West Virginia Consumer Advocate
NASUCA Executive Committee
700 Union Building
Charleston, West Virginia 25301

National Association of State
Utility Consumer Advocates
1133 15th St., N.W.
Suite 575
Washington, D.C. 20005

COMMENTS OF THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES REGARDING THE PROPOSED AMENDMENTS TO THE PUBLIC UTILITY HOLDING COMPANY ACT.

On behalf of the National Association of State Utility Consumer Advocates (NASUCA), I wish to thank you for this opportunity to comment on Title XV of S. 341 which proposes certain amendments to the Public Utility Holding Company Act of 1935 (PUHCA). NASUCA is comprised of 43 state-appointed utility consumer advocates in 38 states and the District of Columbia, representing utility consumer interests in state and federal regulatory agencies and the courts. My name is Billy Jack Gregg. I am the Director of the West Virginia Consumer Advocate Division and am a member of the Executive Committee of NASUCA.

As primary representatives of utility ratepayers, the members of our organization are well aware that the protections in PUHCA are one of our first lines of defense against utility abuses. Accordingly, we are extremely concerned about any effort to dismantle or weaken the ratepayer protections contained in PUHCA. Because Title XV of S. 341 invites the very abuses PUHCA was passed to prohibit, NASUCA must register its strong opposition to the bill.

The concerns that led to the passage of PUHCA fifty-six years ago are still just as important today. NASUCA's consistent position opposing changes to PUHCA which weaken ratepayer protections and allow utility abuses is grounded in a series of resolutions adopted by the organization over a number of years. These positions and resolutions have previously been presented to Congress in written testimony before the Senate Committee on Energy and Natural Resources by Raymon E. Lark, Jr., Director of the Division of Consumer Advocacy of the South Carolina Department of Consumer Affairs in November 1989, and in written testimony before the House Committee on Energy and Commerce by Irwin A. Popowsky, Pennsylvania Consumer Advocate, in October 1990.

The Public Utility Holding Company Act was passed to correct actual abuses by electric holding companies. Under present PUHCA provisions, an electric utility holding company is limited to the business of supplying electricity to its customers within a geographically and electrically integrated system. A holding company is limited in the type of businesses it may acquire, and in turn, non-utility businesses are prohibited from acquiring electric utilities. Any affiliates created by a holding company to own and operate electric generating facilities are strictly governed by the provisions of PUHCA and SEC regulations. These limitations prevent holding companies from using ratepayer monies to subsidize entry into geographically distant regions and entry into speculative enterprises unrelated to utility business. These PUHCA restrictions reduce the risks for both ratepayers and investors.

S. 341 is a wide-ranging attempt to establish a national energy strategy. Unfortunately, Title XV of this bill eliminates certain restrictions on utility holding company corporate structures and diversification. Title XV creates a new category of electric utility called an "exempt wholesale generator" ("EWG"). As the name implies, an EWG is exempt from PUHCA, as are most transactions involving EWG's. There are no restrictions on non-utilities owning an EWG. Furthermore, there are no restrictions on utility ownership of EWG's, nor on the ability of an affiliated EWG to sell electricity back to the utility. The last section of Title XV permits electric utilities to insulate themselves from competition by opting out of purchases from EWG's for up to ten years by simply filing a declaration of such intention with the Federal Energy Regulatory Commission.

NASUCA's principal concerns with Title XV of S. 341 falls into three main areas: (1) self-dealing and cross-subsidization, (2) unfair competition and (3) erosion of state regulatory authority. Under Title XV an electric utility will be able to subsidize the operation of its unregulated EWG subsidiaries with cash provided by its captive utility operations, and will be able to sell electricity to itself at terms not negotiated at arms length.

Competition in the generation of electricity will not be enhanced by Title XV because electric utility-owned EWG's will have immense advantages over truly independent EWG's. Besides having access to monopoly-generated monies through cross-subsidization, utility-owned EWG's will have access to the utility's transmission system for both internal and external sales. Independent EWG's, on the other hand, can be shut out by these transmission bottlenecks controlled by competitors.

Finally, the power of state regulators to control the actions of electric utilities under their jurisdiction will be greatly reduced. If a utility chooses to create EWG's and sell electricity to itself, the transaction is done at wholesale and not retail and is therefore removed from state jurisdiction. If a utility declares that it will not buy power from any EWG, no matter what the price, a state may not question that decision.

Our concerns are not speculative: many of these abuses are real and on-going, and will be exacerbated by Title XV of S. 341. A glimpse of the world without PUHCA protections have been provided by recent cases in Michigan, Arizona and California involving affiliated electric generating companies. These cases show self-dealing with affiliates and challenges to state authority to remedy abuses of the public interest.[1] The concerns raised by these cases underscore the importance of PUHCA in providing protection of the consumer welfare. The members of NASUCA are convinced that abuses would be more likely to result if PUHCA is weakened, as it would be in Title XV of S. 341.

The proposed bill eliminates a number of regulatory safeguards with respect to electric power generators, but provides no assurance that these safeguards will be replaced by true competition. Title XV of S. 341 allows self-dealing, cross-subsidization, and gives the utilities themselves the option of determining whether or not they wish to permit competition in their own service territories. These flaws will only lead to higher electricity rates, a shifting of risks to consumers, and an erosion of state authority over utility service.

Everyone can agree that our nation needs an energy policy. However, we don't have to sacrifice consumer interests to have energy security. Title XV of S. 341 will strip away existing consumer protections, but will not guarantee additional energy supplies at reasonable prices. It will only result in benefits for a few at the expense of the many. For these reasons the National Association of State Utility Consumer Advocates respectfully opposes passage of Title XV of S. 341.

---

[1] An excellent review of these cases and of arguments against weakening PUHCA protections is found in the article "Self-Dealing: The Case Against Removing PUHCA Restrictions on Utility Affiliated Power Producers," by Cynthia Bogorad, The Electricity Journal, (January/February 1991), p. 45.

1991 APR -9 PM 12:47

The Council
City of New Orleans

JOSEPH I. GIARRUSSO
COUNCILMEMBER AT LARGE

DOROTHY MAE TAYLOR
COUNCILMEMBER AT LARGE

PEGGY WILSON
COUNCILMEMBER DISTRICT A

JIM SINGLETON
COUNCILMEMBER DISTRICT B

JACQUELYN BRECHTEL CLARKSON
COUNCILMEMBER DISTRICT C

LAMBERT C. BOISSIERE JR
COUNCILMEMBER DISTRICT D

JOHNNY JACKSON JR
COUNCILMEMBER DISTRICT E

March 21, 1991

The Honorable J. Bennett Johnston
United States Senator
136 Hart Office Building
Washington, D. C. 20510-1802

Re: Senate Energy and Natural Resources Committee Hearings on Amendment of the Public Utility Holding Company Act

Dear Senator Johnston:

We want to thank you for your gracious reception of Councilmen Giarrusso and Boissiere, and legal advisors, last week in Washington during the Energy and Natural Resources Committee hearings on amending the Public Utility Holding Company Act ("PUHCA"). As always, we appreciate the time that you and Committee staff have given the Council in our efforts at developing important regulatory protections for ratepayers in New Orleans.

As you know, the Council believes that it is imperative that Congress resolve the problems facing state level regulators of multistate holding company utilities. As you have recognized, the Grand Gulf dilemma, by reducing the ability of state commissions to oversee utility generation decisions, poses a real threat to consumers in New Orleans, throughout Louisiana, and across the nation. This situation would be further complicated by an amendment to PUHCA which would increase wholesale transactions.

Your proposal to provide state commissions with veto authority over purchases from exempt wholesale generators ("EWGs") is a significant step in protecting consumers. However, such a mechanism only provides the third side of what must be a four-sided cage to protect against the 800 pound gorilla, which multistate holding companies have become. Without the complete cage, holding companies would be able to run rampant over a region, harming consumers who stand in their way.

State regulatory participation when only EWG affiliates are involved would permit holding companies to avoid state regulation through the creation of affiliates they choose not to brand as EWGs. While the Securities and Exchange Commission ("SEC") would continue to be involved, that Commission's recent track record for protecting consumers leave the adequacy of this protection seriously in doubt. What ratepayers need is a comprehensive program that would protect state level regulation over utility generation.

The linkage of such a solution to the amendment of PUHCA can not be in doubt. If utilities are to make the right generation decision to benefit consumers, rather than maximize profits, state level regulatory involvement is vital. However, if the status quo is maintained, multistate holding companies could form non-EWG affiliates for wholesale transactions with their operating utilities, rather than purchase power from a more efficient and (from a consumer perspective) economically attractive independent alternative. Without state regulatory involvement, independent power development would be stunted, rather than encouraged.

In addition, as the holding companies' representative, Charles Patrizia, noted, PUHCA acts to ensure that registered holding companies operate on an integrated and economically-dispatched basis for the benefit of system consumers. As such, the Act requires holding companies to focus their efforts on serving a single utility system. If PUHCA is amended to permit registered holding companies to expand their horizons, state level regulators must be empowered to ensure that system consumers are not harmed.

We also remain concerned about a provision in your proposal that would authorize multistate holding companies to "spin-off" generating plants free from PUHCA review. These holding companies would be able, upon the concurrence of one state commission, to partake in an activity which could have a substantial effect on system consumers, with absolutely no review of the transaction's effect on consumers outside of the one state with jurisdiction. We believe strongly that such a provision should be stricken from your bill. Multistate holding companies have no valid reasons for supporting such a proposal, except as it pertains to their desire to escape regulatory review of their activities. This is not consistent with the spirit behind the proposals in favor of amending PUHCA.

The Council and our legal advisors hope to continue working with you and your staff so that we may develop an acceptable regulatory section for your bill. We would be glad to meet with you at your convenience to listen to any thoughts you may have. Until then, thank you again for the opportunity to testify before your Committee.

Sincerely,

Joseph I. Giarrusso
City Council President

Dorothy Mae Taylor
Dorothy Mae Taylor
Councilwoman-at-Large

Peggy Wilson
Peggy Wilson
Councilman, District "A"

Jim Singleton
Councilman, District "B"

Jacquelyn B. Clarkson
Jacquelyn Clarkson
Councilman, District "C"

Lambert C. Boissiere, Jr.
Councilman, District "D"

Johnny Jackson, Jr.
Councilman, District "E"

CUR 91-96L-3

APPENDIXES TO MARCH 18, 1991 HEARING

(Section 5101 of Title V)

Appendix I—Responses to Additional Questions

NRDC

Natural Resources Defense Council

1350 New York Ave. NW
Washington, DC 20005
202 783-7800
Fax 202 783-5917

April 4, 1991

The Honorable J. Bennett Johnston
Chairman
Senate Committee on Energy and
  Natural Resources
364 Dirksen Senate Office Building
Washington, DC 20510

Dear Chairman Johnston:

This is in response to your letter of March 21, 1991 transmitting a question relating to the "WEPCO" issue and the testimony I presented on that issue before your Committee last month. Again I wish to thank you for the consideration you gave to my views at the hearing.

Your letter asks for additional information on the nature of a WEPCO compromise that would be acceptable to NRDC and for our views on the nature and feasibility of an administrative exclusion for pollution control projects.

As I indicated in my testimony, there are two important values served by the Clean Air Act's existing definition of the term "modification:" protection against adverse local air quality impacts that could result from increases in actual emissions due to plant modifications; and achievement of reductions in national and regional air pollutant emissions resulting from the application of more stringent new source control requirements to modified plants. NRDC is prepared to explore and support changes in interpretations of the Act's requirements that would be equally effective in promoting these important values.

In my opinion, such changes should be pursued administratively rather than legislatively for the reasons I mentioned in my prepared testimony.

I believe it is feasible for EPA to craft special administrative provisions for pollution control projects that would protect the local air quality and larger-scale emission reduction objectives of the Act's modification provisions.

100% Recycled Paper

40 West 20th Street
New York, New York 10011
212 727-2700
Fax 212 727-1773

90 New Montgomery
San Francisco, CA 94105
415 777-0220
Fax 415 495-5996

617 South Olive Street
Los Angeles, CA 90014
213 892-1500
Fax 213 629-5389

212 Merchant St., Suite 203
Honolulu, Hawaii 96813
808 533-1075
Fax 808 521-6841

First, to protect against adverse local air quality impacts, such special administrative provisions should require that there be no increase in actual emissions. It may be possible for EPA to acquire sufficient information for some categories of sources to establish accurate and enforceable forecasts of future actual emissions that do not require assuming full-load operation of such sources. We are willing to explore and evaluate options for such forecasts.

Second, to prevent loopholes for projects that are functionally equivalent to new source investments, the definition of pollution control projects should be limited in scope to changes in equipment and/or fuel that reduce emissions at the source in question. Other investments, such as projects that improve the availability or economics of a source's production capacity, should be evaluated on a level playing field with other projects that expand or replace existing capacity and thus should not be included in the scope of a special pollution control project provision.

I hope these responses are useful. I would be happy to discuss these issues further with you or others that are interested in resolving the WEPCO matter in an environmentally sound manner.

Sincerely,

David G. Hawkins

David G. Hawkins
Senior Attorney

American Electric Power
Service Corporation
801 Pennsylvania Avenue NW
Suite 214
Washington DC 20004

AEP
AMERICAN
ELECTRIC
POWER

Dale E. Heydlauff
Director
Federal Agency Affairs
202 628 1645

April 9, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
364 Senate Dirksen Building
Washington, D.C. 20510

Attn: Donald F. Santa, Jr., Majority Counsel

Dear Mr. Chairman:

On behalf of Anthony J. Ahern, I hereby transmit to you his responses to the questions you posed to him in your letter of March 21, 1991. I hope you find his answers satisfactory. If you have any questions about them, please call Mr. Ahern directly at 614/223-1270.

Respectfully yours,

Dale E. Heydlauff
Dale E. Heydlauff

Attachments

April 9, 1991

ANSWERS BY ANTHONY J. AHERN, P.E., MANAGER, ENVIRONMENTAL AND TECHNICAL ASSESSMENT DIVISION, AMERICAN ELECTRIC POWER SERVICE CORPORATION TO QUESTIONS POSED BY THE HONORABLE J. BENNETT JOHNSTON, CHAIRMAN, COMMITTEE ON ENERGY AND NATURAL RESOURCES

1. How long does a power plant last?

   - What is the normal operating life of the type of coal-fired power plant that might be subject to WEPCo?

     There is no universal understanding of "normal operating life" of a coal-fired power plant. Attached are three tables representing:

     Table 1: Retired U.S. Fossil-Fuel Steam Electric Units Greater Than 10 MW Size Through 1988

     Table 2: Retired U.S. Coal-(or Dual Fuel)-Fired Units by Age Class (All Sizes)

     Table 3: Installed U.S. Steam Electric Coal-Fired Units by Age Class (Attachment 1)

     Table 3 reveals that the bulk of U.S. coal-fired generating capacity has been installed since 1945. The decade immediately following World War II saw the laying of the technological and engineering foundation for today's high-efficiency coal-fired units, particularly with respect to boiler temperature and pressure capabilities. Although for accounting purposes generating units have been depreciated over a 33-year period, it is currently forecasted that modern coal-fired units which were installed in the post-war period based on then-current technology will have economic lives of approximately 50 to 65 years of age.

   - Over the course of the normal life of such a power plant, what types of items would need to be replaced?

     It is important to recognize that units do not "wear" identically even when they are comprised of similar if not identical components. What this means is that all units vary one from the other in connection with component repair/replacement patterns. Over the period from 1945 to 1990, the industry has made a concerted effort to improve the performance and economics of power generating units by constructing new units having improved components and configurations and by installing certain of these improvements into existing generating units when repairing failed or deteriorated components.

As a result, certain changes at existing units have not been replacements in the strict sense. Instead, utilities have seized upon technological advances by installing improved, newly engineered types of components to augment performance. For example, beginning in the 1960's, utilities have added sootblowers at units to address performance problems associated with unanticipated changes of fuel characteristics and have converted from forced draft to balanced draft in order to facilitate accessibility and ease of maintenance.

Utility units are comprised of complex equipment systems that are required to operate under stressful and demanding physical conditions. As a result, utility boiler components are subject to the constant need for repair, replacement, and maintenance. A Utility Data Institute survey of 300 individual utilities operating 725 fossil-fueled power plants with more that 2,000 non-NSPS steam electric units revealed the following: About $34 billion was spent from 1981-1988 by U.S. utilities on maintenance for fossil-fueled units, of which some $20 billion was on boiler maintenance alone. These expenditures were undertaken to repair or to replace hundreds of thousands, even millions, of individual pieces of equipment. Almost every coal-fired unit has had one or more major component replaced. These include air heaters, pulverizers, turbine blades, and numerous other components. Without these repairs, it would be impossible for boilers to operate, much less for the utility industry to maintain a reliable economic electric supply.

2. Assumptions behind the emissions trading scheme.

   - To your knowledge, when EPA analyzed the emissions trading plan that is now part of the Clean Air Act, what assumptions were made regarding the operating life of existing coal-fired power plants?

We understand that EPA engaged ICF Resources, Inc. to conduct much of the analysis of the emissions trading plan that is now part of the Clean Air Act. Attached is a letter from ICF Resources to Robert A. Beck of the Edison Electric Institute dated July 26, 1989, that details the assumption used in EPA analysis. (Attachment 2). The third paragraph of the letter to Mr. Beck, signed by Kenneth Schweers, President of ICF Resources, Inc., explains that in the "low" case a 55-year life was assumed for all units larger than 50 MW, and in the "high" case a 65-year life was assumed for all units larger than 50 MW. Mr. Schweers states that "prior to 1984, EPA had assumed that all fossil-fueled power plants had a physical useful operating lifetime of forty-five years for all of the analysis performed by ICF for EPA." Mr. Schweers writes that "this assumption was subsequently revised to 60 years for the 1984 interim EPA base case and all following analyses as it became obvious that existing power plants were being operated for periods longer than 45 years." Mr. Schweers also indicates in the fourth paragraph that "it was assumed that all large oil- and coal-fired power plant units at thirty years of age would engage in refurbishment activities sufficient to achieve the above-noted power plant lifetime assumptions". On Page 2 of the July 26, 1989, letter the second bullet item on that page states, "Thus for purposes of the recent EPA forecasts, the act of refurbishment . . . was not assumed by EPA to require any refurbished plant to meet tighter new source emission controls." Also attached is Mr. Beck's July 12, 1989, letter that inquired about the assumptions that EPA instructed ICF to use in the analysis to which Mr. Schweers' July 26, 1989 letter responded. (The contrast between appearance and reality is invariably a matter of concern when regulatory treatment hangs in the balance. The reason for seeking the proposed WEPCo fix is precisely because the assumed ease of refurbishing power plants at age 30 is by no means a certainty.)

3. Timing for Clean Air compliance decision.

- When must American Electric Power make its decisions as to how it will comply with the acid rain title of the Clean Air Act Amendments?

In order to comply with the Phase I January 1, 1995 deadline, American Electric Power needs to make its compliance decisions by no later than the summer of 1991 on those units where there will be changes to the physical structure. This holds whether or not the means of compliance is to be a fuel switch or retrofit of control technology. It bears emphasis that the point of decision at numerous units across the AEP System will soon be upon us.

- If WEPCo has not been clarified by that time, how will this affect American Electric Power's compliance strategy?

If great uncertainty persists whether or not new source review will be required regarding changes that may be necessary to comply with Phase I of the 1990 Amendments to the Clean Air Act, then utilities like American Electric Power will be highly motivated to select compliance strategies which avoid the necessity of physical changes at its plants. The result of this is that some cost-effective compliance strategies may have to be eliminated from consideration.

4. Capacity utilization

- At what capacity factor are base load electric power plants ordinarily utilized?

"Base load" electric generating units, despite the implications of their categorization, are ordinarily utilized over a wide range of annual capacity factors. The attached graph shows the average AEP System capacity factor and the capacity factors for three individual units on the AEP System for the period 1980 to 1989. (Attachment 3). During this 10-year period the average annual capacity factor was approximately 55 percent plus or minus 5 percent. However, _individual units_ had capacity factors that range from a low of thirty percent to a high of 90 percent. Among the many variables that can affect a unit's capacity factor in any one year are: the number of forced outages which is often related to the unique characteristics of that unit; the number of scheduled outages for the unit which is often related to the utility system of which the unit is a part; the dispatch of the unit which is affected by the economics relative to other units on the utility system; and overall customer electricity demand which can be significantly affected by the condition of the economy and weather. A specific capacity factor percentage -- or even a range of percentages -- cannot be advanced as entirely descriptive of base load operation.

5. Best Available Control Technology

- In terms of cost and effectiveness, please compare BACT for NOX control, which I presume would be selective catalytic reduction, with the standard under § 5101 which incorporates § 407 of the Clean Air Act Amendments of 1990.

American Electric Power understands that EPA's current position on BACT for NOX is application of low-NOX burners for a coal-fired unit. However, EPA Region II made a BACT determination recently for NOX that established a NOX emission rate of .03 lbs. NOX per million BTU for a dry bottom wall-fired pulverized coal unit. Section 407 of the Clean Air Act Amendments of 1990 establishes a NOX emission rate requirement of .45 lbs. NOX per million BTU at tangentially fired units and .50 lbs. NOX per million BTU for dry bottom wall-fired units. Thus the EPA's most recent BACT determination for NOX is more stringent than the NOX requirements in § 407.

Attached is a paper titled "Retrofit Costs and Performance of NOX Controls at 200 U.S. Coal-Fired Power Plants" by T.E. Emmel and M. Maibodi of Radian Corporation that provides data from which cost-effectiveness inferences can be drawn for low NOX burner (LNB), overfire air (OFA), natural gas reburn (NGR), and select catalyst reduction (SCR). (Attachment 4). We believe that the numbers presented in this paper are representative of approximate costs. As a further reference, attached is an August 1, 1990, letter from Kurt E. Yeager of the Electric Power Research Institute to the Honorable Quentin Burdick, Chairman, Senate Environment and Public Works Committee. (Attachment 5). This letter describes the paucity of favorable experience with SCR in this country. It also describes the particular problem that use of medium and high sulfur fuels may pose for the cost and reliability of SCR.

- What happens when EPA must decide on a case-specific basis what BACT will be? How long does this take?

It is difficult to predict the outcome of case-specific BACT determinations by EPA. In general, the trend appears to be that with each plant-specific determination of BACT, emissions rates are ratcheted downward. There is no specific mandated timeframe under which EPA must make a BACT determination. It is difficult to project for future cases how long it would take EPA to make a BACT determination, but industry experience indicates that a year or more is not an unreasonable estimate.

6. Protection of Local Air Quality

- Please respond to Mr. Hawkins' contentions regarding the need for new source review when a stationary source undertakes physical changes in order to protect local air quality in nonattainment areas and PSD areas.

A surgically focused interpretive ruling or appropriately directed legislative action addressing WEPCo would do nothing to threaten local air quality, Mr. Hawkins' protestations to the contrary notwithstanding. Legislative action of the sort supported by the Edison Electric Institute and other utility trade associations does not disturb one iota the fundamental Clean Air Act requirement that state implementation plans assure the attainment and maintenance of national ambient air quality standards in the vicinity of stationary sources such as power plants. This obligation long predated EPA's WEPCo determination in 1989 and is in no way threatened by the narrowly drawn amendments that are supported by my testimony. To be sure, the Clean Air Act's requirement for state implementation plans go so far as to require their revision if their continued attainment and maintenance is threatened. See Clean Air Act § 110(a)(2)(H)(ii), 42 U.S.C. § 7410(a)(2)(H)(ii). Additionally, the Clean Air Act makes it clear that state implementation plans must achieve prevention of significant deterioration requirements as well, § 110(a)(2)(J), 42 U.S.C. § 7410(a)(2)(J); 40 C.F.R. § 51.166(c)(3). Reinforcing the foregoing is the explicit requirement that "modifications" of existing sources, as defined in Clean Air Act § 111(a)(4), 42 U.S.C. § 7411, undergo the rigors of prevention of significant deterioration review, § 165(a), 42 U.S.C. § 7475(a).

Moreover, these basic requirements are entirely independent of -- and are in no way diminished by -- the possibility that an existing source must undergo new source review under WEPCo or for any other reason.

To illustrate even more clearly that the "WEPCo fix" advocated here reflects the incision of a scalpel rather than the broad thrust of a meat axe, an appropriate interpretive ruling or legislative change would not authorize any increase in the short-term emission rate of a unit. Establishment of requirements to accomplishment attainment with short-term national ambient air quality standards (*e.g.*, 3-hour and 24-hour standards for sulfur dioxide) is based on increasingly sophisticated computer models which use *maximum* short-term source emission rates as basic input for air quality model predictions. (In Ohio, sulfur dioxide emission limitations have traditionally been based upon hourly air quality predictions for a period of five consecutive years using officially sanctioned meteorological data and encompassing hundreds of receptor points; in short, sulfur dioxide emission limitations are based on literally millions of discrete predictions. This well-entrenched practice is in no way threatened by the proferred language for fine-tuning *WEPCo*.) As to annual emissions, EPA's rules governing prevention of significant deterioration have since their initial promulgation allowed units to increase annual utilization, and therefore annual emissions, without new source review. *See* 40 C.F.R. § 51.165(a)(1)(v)(C)(6). Again, most if not all current-day emission limitations are based on annual emission factors that represent operations 365 days a year at maximum production levels.

Finally, as we have seen above, where there is reason to believe that increased utilization might threaten local air quality, either EPA or the states are legally required to conduct air quality analyses to determine compliance with or to take affirmative action to assure compliance with ambient air quality requirements. If Mr. Hawkins' eloquent testimony has any major shortcoming it lies in its failure to view the WEPCo relief sought by the utilities in the context of the Clean Air Act as a whole, either pre- or post-1990 Amendments. These pervasive requirements will in no way be disturbed by the relief sought before the Congress or the Administration.

Attachment 1

TABLE 1

RETIRED U.S. FOSSIL-FUELED STEAM[1]
ELECTRIC UNITS GREATER THAN 10 MW SIZE THROUGH 1988

RETIREMENT AGE GROUP (YEARS)	ALL FOSSIL-FUELED UNITS NO. OF UNITS	CAPACITY MW	UNITS ≥ 50 MW	LARGEST UNIT (MW)	AVERAGE SERVICE LIFE OF UNITS ≥ 50 MW	ONLY COAL-FIRED UNITS NO. OF UNITS	CAPACITY MW	UNITS > 50 MW	LARGEST UNIT MW	AVERAGE SERVICE LIFE OF UNITS ≥ 50 MW
≥ 50	79	2,074	13	110	49.5	26	611	0	38	N.A.
46-49	121	3,849	27	175	47.5	57	2,209	18	175	46.5
41-45	139	4,091	26	208	43.0	76	2,359	17	208	42.0
36-40	91	3,101	22	173	38.5	62	1,408	10	117	37.0
31-35	131	4,217	34	153	33.5	56	1,877	18	113	32.5
≤ 30	161	3,986	25	161	26.5	92	2,155	16	143	27.5
TOTAL	722	21,318	147	...	..	369	10,619	79	...	..

TABLE 2

RETIRED U.S. COAL (OR DUAL FUEL) -FIRED UNITS BY AGE CLASS[1]
(ALL SIZES)

AGE CLASS (YEAR-ON-LINE)	TOTAL UNITS	RETIRED DURING	TOTAL MW	AVERAGE UNIT MW	LARGEST UNIT SIZE	AVERAGE SERVICE LIFE (YEARS)
1925 - 1929[2]	157	1960 - 1987	4,271	27.2	38	47.5
1930 - 1934	46	1966 - 1985	1,167	25.4	64	45.0
1935 - 1939	77	1951 - 1988	1,530	19.9	60	43.5
1940 - 1944	76	1956 - 1988	2,108	27.7	175	43.5
1945 - 1949	93	1960 - 1988	2,028	21.8	208	40.0
1950 - 1954	69	1967 - 1988	1,806	26.2	117	37.5
1955 - 1959	22	1976 - 1988	1,143	52.0	112.5	32.5
1960 - 1964	6	1983 - 1988	171	28.4	142.0	26.5
1965 - 1969	3	1987 - 1988	31	10.0	12.5	20.5
1970 - 1974	1	1988	13	13.0	13.0	14
TOTAL	550	...	14,268	25.9	...	...

[1] Data are only included for units where fuel (and its analysis), capacity, in-service date, and retirement years are known. This list may be underestimated by 1 to 2% which is statistically insignificant.

[2] Only five units built prior to 1925 are still in service; but four of them are either in reserve shutdown or deactivated status. Largest of these units is Ohio Edison Co.'s 24 MW Edgewater Unit #2.

Technical Assessment Section - 8/30/89

TABLE 3

INSTALLED[1] U.S. STEAM ELECTRIC COAL-FIRED UNITS BY AGE CLASS (EEI POWER STATISTICS DATA BASE)

AGE-CLASS (YEAR-ON-LINE)	TOTAL UNITS	AVERAGE UNIT MW	LARGEST UNIT MW	TOTAL CAPACITY MW (NET)	AVERAGE CURRENT OPERATING LIFE - YEARS
1917 - 1924[2]	3	13.6	24	40.8	68
1925 - 1929	5	11.1	14	55.5	62
1930 - 1934[3]	6	18.1	50	108.5	57
1935 - 1939[4]	12	14.5	50	173.8	52
1940 - 1944	41	38.2	95	1,566.5	47
1945 - 1949	103	35.7	107	3,677.0	42
1950 - 1954	241	83.3	265	20,075.5	37
1955 - 1959	220	134.5	326	29,590.0	32
1960 - 1964	156	172.4	647	26,895.0	27
1965 - 1969	142	285.9	850	40,598.0	22
1970 - 1974	123	517.9	1300	63,702.0	16.5
1975 - 1979	106	498	1300	52,788.0	11
1980 - 1984	106	316.5	1300	34,233.0	6
1985 - 1988	33	579.3	1300	19,120.0	2.5
TOTAL	1,298	240.9	--	312,650.8[5]	--

NOTES:

[1] Includes currently-operating, reserve shut-down, and/or deactivated units.

[2] No statistics available prior to 1917. Oldest coal-fired unit in operation (reserve shut-down) to date is Iowa Electric Light & Power's Sixth Street unit (72 years, 7 MW).

[3] Only one coal-fired unit (reserve shut-down status) greater than 50 MW is in-service for 59 years. Highest capacity factor of this unit was less than 20% during 1950 - 1983 (only period during which data is available).

[4] Only one coal-fired unit (deactivated status) greater than 50 MW is in service for 54 years. Highest capacity factor of this unit was less than 25% during 1957 to 1985.

[5] 292,575 MW of these are operated by electric utility companies.

Note that no coal-fired unit larger than 25 MW size is currently in-service for 60 years or more. The oldest coal-fired plant larger than 16 MW is the Ohio Edison Co.'s Edgewater Unit 2 (24 MW) which has been in service for 65 years (reserve shut-down status for the past seven years).

Technical Assessment Section - 8/30/89

Attachment 2

ICF RESOURCES
INCORPORATED

9300 Lee Highway
Fairfax, Virginia
22031-1207

Phone 703 934-3000
Fax 703 694-3349
703 934-9740

July 26, 1989

Mr. Robert A. Beck
Director
Clean Air, Fossil Fuels and Natural Resources
Edison Electric Institute
1111 19th Street, N.W.
Washington, D.C. 20036

Dear Mr. Beck:

In your letter of July 12, 1989, you raised a number of questions regarding the assumptions used in the 1989 Base Case analyses performed by ICF Resources for EPA. We are happy in this letter to respond to these questions. In addition, we have enclosed a copy of the report *1989 EPA Base Case Forecasts* for your use and review.

The 1989 EPA Base Case analyses were conducted by ICF for EPA's Office of Policy, Planning and Evaluation to reassess future utility air emission trends using up-to-date sets of assumptions. In the Base Case analyses, EPA had us examine two cases — a "High" case and "Low" case — so as to present a reasonable possible range of future utility emissions. To achieve this result, these cases incorporated different sets of assumptions that would respectively result in higher and lower utility SO_2 emissions trends.

Fossil powerplant lifetime assumptions were among the important differences in assumptions between the two cases: 55 years was assumed for all large (i.e., larger than 50 megawatt) fossil steam generating units in the Low case, while 65 years was assumed for all large fossil steam units in the High case. This difference in assumptions obviously has an important effect on utility emission trends, as demonstrated in the ICF analysis. Before 1984, EPA had assumed that all fossil-fueled powerplants had a physical, useful operating lifetime of 45 years for all of the analyses performed by ICF for EPA. This assumption was subsequently revised to 60 years for the 1984 Interim EPA Base Case and all following analyses as it became obvious that existing powerplants were being operated for periods longer than 45 years.

For both of the cases evaluated for the 1989 EPA Base Case forecasts, it was assumed that all large oil- and coal-fired powerplant units at 30 years of age would engage in refurbishment activities sufficient to achieve the above-noted powerplant lifetime assumptions. Those units explicitly assumed to repower using a "generic clean coal" technology were not included as part of this universe of "life extended" powerplants. About 350 gigawatts of capacity (about half of all fossil fuel-fired capacity expected to be on line by 2010) will undertake life extension activities by 2010 under these specific assumptions.

Consistent with previous ICF modeling efforts, it was assumed that net dependable capacity and reliability of existing powerplants would be maintained at design levels for their entire 55 to 65 year lifetime. However, unit heat rates were assumed to increase by 0.25% per year to reflect powerplant aging (i.e., to reflect progressive deterioration in

Mr. Robert A. Beck
July 26, 1989
Page 2

potential power output), combined with a one-time 5% decrease in heat rates assumed to occur at the time of refurbishment (to reflect the restoration of the powerplant to something close to its original design operating efficiency as a result of refurbishment). These assumptions have been included in all of the EPA analyses by ICF since the 1985 EPA Base Case assessments began in 1984.

Two additional issues related to powerplant refurbishment that were raised either directly or implicitly in your letter include the following:

- The powerplant lifetime/refurbishment assumptions in the 1987 Interim EPA Base Case included an assumed average cost of $200 per kilowatt in early 1986 dollars for all refurbished units. No assumptions regarding the costs of refurbishment were explicitly made in the more recent analyses, however, because the costs of life extension were assumed to be sufficiently low (at $200 per kilowatt in early 1986 dollars or less) that all units would be refurbished and their lives extended under all the environmental regulatory scenarios evaluated. Since these refurbishment costs will be incurred in all cases, they do not affect the analysis of different environmental regulatory scenarios.

- As stated on page 29 of the enclosed report, "it was assumed by EPA that the recent WEPCo decision would not result in any significant number of powerplants having to comply with NSPS upon refurbishment." It was also assumed that refurbishment would not result in more stringent emission requirements under PSD. Thus, for purposes of the recent EPA forecasts, the act of refurbishment, (which, for the purposes of the EPA Base Case, means efficiency improvements and other maintenance designed to enable an additional 25-35 years of acceptable operation up to design capacity) was not assumed by EPA to require any refurbished plant to meet tighter new source emission controls.

We hope that this information is useful to you and adequately addresses your questions. Please call should you have any further questions.

Sincerely,

Ken Schweers

Kenneth A. Schweers
President
ICF Resources Incorporated

EDISON ELECTRIC INSTITUTE The association of electric companies

1111 19th Street, N.W
Washington, D.C. 20036-3691
Tel (202) 778-6400

July 12, 1989

Mr. Kenneth A. Schweers
ICF Resources Incorporated
9300 Lee Highway
Fairfax, Virginia 22031-1207

Dear Mr. Schweers:

I read with interest a recent article in Inside EPA entitled "EPA Predicts Less Dramatic Decline of SO_2 Emissions, Reaching Consensus," a copy of which is enclosed. The article states that your company prepared, on behalf of EPA, forecasts "through the year 2000 [of] trends in utility air emissions, utility capacity and generation levels, utility fuel consumption and regional coal production." The article states that ICF prepared two base cases which utilized plant retirement dates of 55 and 65 years. I understand that these forecasts are being used to support the Administration's Clean Air Act bill.

I am interested in learning more about the assumptions that EPA had you use in these forecasts. Specifically,

1. What assumptions, if any, were made concerning deterioration and restoration of unit capacity as the units aged?
2. What assumptions were made concerning the amount and timing of investments in programs that would be necessary to operate plants reliably to 55 or 65 years?
3. What assumptions were made concerning the applicability of new source performance standards and the prevention of significant deterioration program with regard to investments made in programs to restore capacity and to maintain acceptable levels of reliability and availability during a 55 to 65 year life?

EDISON ELECTRIC
INSTITUTE The association of electric companies

1111 19th Street, N W
Washington, D C 20036-3691
Tel (202) 778-6400

Mr. Kenneth A. Schweers
page 2

4. When did EPA first have you assume that source owners would undertake programs to restore capacity and to enable reliable operations for 55 or 65 years?

5. In the most recent EPA studies, how many units were assumed to undertake programs directed at restoring capacity, availability, and reliability during the 55-65 year facility life?

Thank you for your help in clarifying the assumptions used in these EPA analyses. Please call me if you have any questions concerning this request.

Sincerely,

RABeck

Robert A. Beck
Director
Clean Air, Fossil Fuels
and Natural Resources

Enclosure

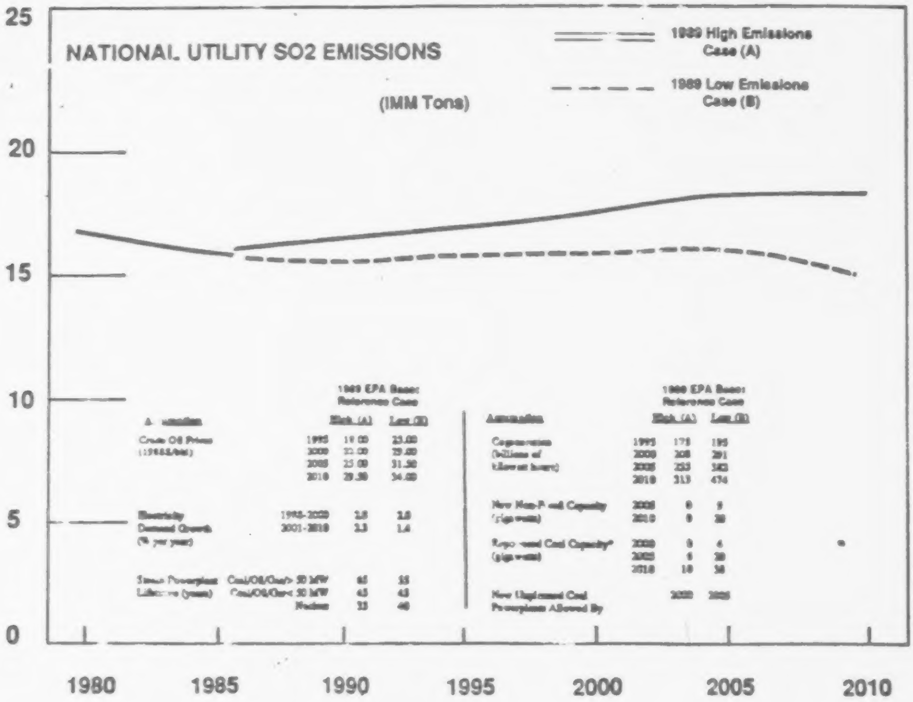
EPA PREDICTS LESS DRAMATIC DECLINE OF SO2 EMISSIONS, REACHING CONSENSUS

EPA's Office of Policy, Planning & Evaluation has revised its base for predicting future emissions of sulfur dioxide, from an earlier draft version yielding a continual rise in emissions to a final version, showing a less drastic decline. The minor revisions were made in response to harsh criticisms levied by EPA's Air Office, which argued that the assumptions in the draft used to yield a significant new decline in emissions after the year 2000 were unrealistic (Inside EPA, March 10, p1). OPPE in the draft had devised a "high" and "low" emissions scenario, with the low case supporting industry assertions that emissions will not rise quickly and will ultimately decline without regulation (Inside EPA, March 10, p4). The most recent base case departed somewhat from EPA's 1987 "interim" base case -- the predecessor to the draft base case -- which showed SO2 emissions increasing at a faster rate.

The final *1989 Base case forecasts*, prepared by ICF, Incorporated for EPA, forecast through the year 2010 future trends in utility air emissions, utility capacity and generation levels, utility fuel consumption and regional coal production. The document is designed to update EPA's 1987 "interim base case," to provide more recent analyses that will serve as a basis for analyzing economic and emissions impacts of various clean air proposals. The final plan, like the draft, uses two base cases, a high case A and a low case B, to present a "reasonable possible range" of electric utility air emissions over the next two decades. The Air Office had primarily attacked assumptions used to derive the low emissions scenario and OPPE has

continued on next page

EPA's NEWEST FORECAST ON SO2 EMISSIONS



Assumption		1989 EPA Base: Reference Case High (A)	Low (B)
Crude Oil Prices (1988$/bbl)	1995	19.00	23.00
	2000	22.00	29.00
	2005	25.00	31.50
	2010	29.50	34.00
Electricity Demand Growth (% per year)	1995-2000	2.5	2.0
	2001-2010	2.3	1.4
Steam Powerplant Lifetime (years)	Coal/Oil/Gas > 50 MW	65	55
	Coal/Oil/Gas < 50 MW	45	45
	Nuclear	35	40

Assumption		1989 EPA Base: Reference Case High (A)	Low (B)
Cogeneration (billions of kilowatt hours)	1995	175	195
	2000	208	291
	2005	233	382
	2010	313	474
New Non-Fossil Capacity (gigawatts)	2000	0	9
	2010	0	28
Repowered Coal Capacity* (gigawatts)	2000	0	6
	2005	4	28
	2010	10	58
New Unplanned Coal Powerplants Allowed By		2020	2005

*Includes 50% increase in capacity due to repowering

Figure 1. Near-term utility SO2 emissions are similar, but High Case emissions grow steadily after 2000, while Low Case emissions decline slightly.

EPA's DRAFT BASE CASE FOR SO2 EMISSIONS

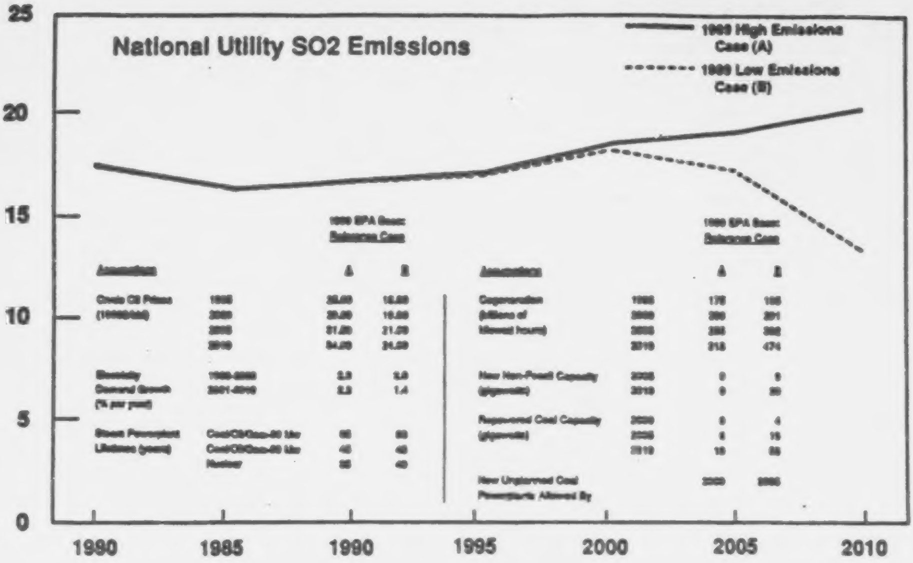


Figure 1: Near-term SO2 emissions are similar, but Case A emissions grow steadily after 2000, while Case B emissions decline.

responded by revising some of those figures in the final document. "This has been a long process, but we believe we have successfully developed two plausible scenarios of future emissions; one scenario resembling our previous 1987 interim base case and the other reflecting reasonable alternative assumptions resulting in lower emissions," says a memo from EPA to base case reviewers, who received the revised document this week.

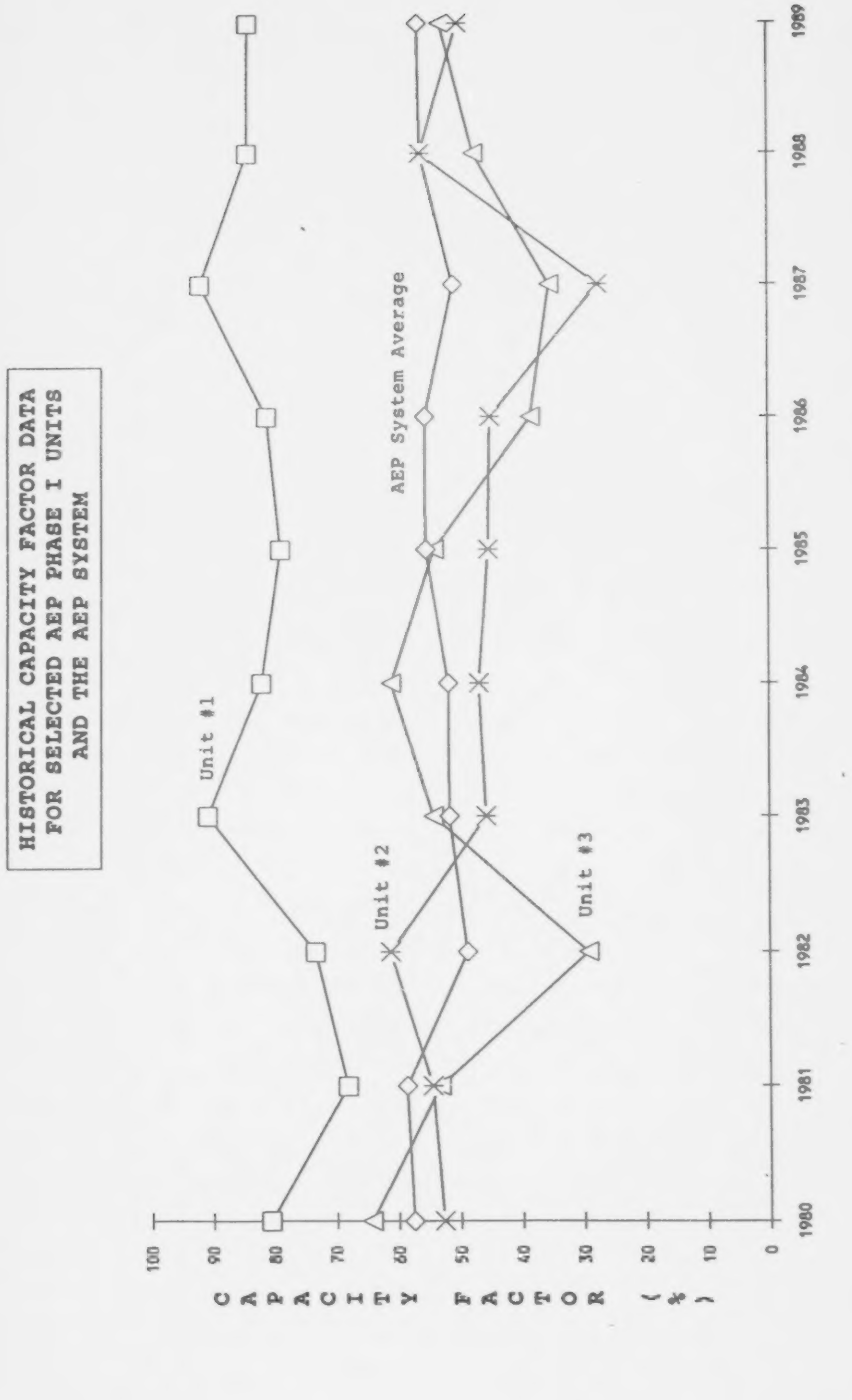
The high emissions case shows that SO2 and NOx emissions will rise moderately in the near-term and grow in the long-term, while the low emissions case remains constant in the near-term, rises slightly in the year 2000, declines and then plateaus after that point *(see chart.)* An agency source explains that cases A and B reveal lower increases in SO2 than EPA had predicted in its 1987 interim base case, but fails to show the "drop off" in emissions forecasted in OPPE's earlier draft version.

The most significant change in assumption from the draft that OPPE made involved the year at which plants are likely to retire. If the older, more inefficient plants with less sophisticated pollution controls are predicted to retire earlier, the result will be a lower emissions forecast. "The plant life issue drives the way emission trends look in the future," says one agency source. Another explains the difficulty in predicting power plant life: "There's no good estimates on this. No one knows when these will cease to be useful boilers." Responding to concerns that it had overestimated the retirement rate, OPPE changed -- from the draft to the final version -- the age at which plants retire in the low emissions case from 50 to 55 and from 60 to 65 in the high emissions case.

The assumptions governing the degree to which plants will switch to more efficient and cleaner coal capacity through repowering were also "tightened," says one agency source, to assume less repowering in the low emissions case. The Air Office said that OPPE had significantly overestimated the amount of repowering that would occur in case B.

NEW ASSOCIATION FORMED TO ADDRESS BIOTREATMENT. The Washington, D.C. Applied Biotreatment Asn. plans to explore the issue, which involves the use of bacteria to decompose waste. The core group of the newly organized association consists of 10 member companies, who will recommend different treatment technologies and interface between environmental services groups and waste-generating industries.

Attachment 3



HISTORICAL CAPACITY FACTOR DATA FOR SELECTED AEP PHASE I UNITS AND THE AEP SYSTEM

Attachment 4

RETROFIT COSTS AND PERFORMANCE OF NO_x CONTROLS AT 200 U.S. COAL-FIRED POWER PLANTS

T. E. Emmel
M. Maibodi
Radian Corporation
3200 E. Chapel Hill Road
Research Triangle Park, North Carolina 27709

RETROFIT COSTS AND PERFORMANCE OF NO_x CONTROLS AT 200 U.S. COAL-FIRED POWER PLANTS

ABSTRACT

This paper presents the results of a study conducted under the National Acid Precipitation Assessment Program by the U.S. Environmental Protection Agency's Air and Energy Engineering Research Laboratory. The objective of this research program was to significantly improve engineering cost estimates currently being used to evaluate the economic effects of applying sulfur dioxide (SO_2) and nitrogen oxide (NO_x) controls at 200 large SO_2-emitting coal-fired utility plants. To accomplish the objective, procedures were developed and used that account for site-specific retrofit factors. The site-specific information was obtained from aerial photographs, publicly available data bases, and input from utility companies. Cost results are presented for the following control technologies: low NO_x combustion or natural gas reburn, and selective catalytic reduction. Although the cost estimates provide useful site-specific cost information on retrofitting NO_x controls, the costs are estimated for a specific time period and do not reflect future changes in boiler and coal characteristics (e.g., capacity factors and fuel prices) or significant developments in control technologies that would change the cost and performance estimates.

RETROFIT COSTS AND PERFORMANCE OF NO_x CONTROLS AT 200 U.S. COAL-FIRED PLANTS

INTRODUCTION

The objective of the National Acid Precipitation Assessment Program (NAPAP) study of 200 U.S. coal-fired power plants was to improve cost estimates being used to evaluate the economic effect of retrofitting sulfur dioxide (SO_2) and nitrogen oxide (NO_x) controls at coal-fired utility plants. Although study resources were primarily focused on the retrofit cost of SO_2 controls, cost estimates were developed for low NO_x combustion controls [low NO_x burners (LNB), overfire air (OFA), or natural gas reburning (NGR)] and selective catalytic reduction (SCR) for the boilers at each plant.

Figure 1 shows the phases in which the NAPAP study of 200 plants was conducted. In Phase I, detailed site-specific procedures were developed with input from a technical advisory committee. In Phase II, these procedures were used to evaluate retrofit costs at 12 plants using data collected from site visits (1). Based on the results of this effort, simplified procedures were developed to estimate site-specific costs without conducting site visits. For LNB and OFA, performance-estimating procedures for NO_x reduction were developed with input from a consultant (2). SCR procedures were tested and revised based on the results of a parallel program effort in which five coal-fired power plants in Germany were evaluated (3). In Phase III, the simplified procedures were used to estimate NO_x control cost and performance for 188 plants. The results of this effort were sent to each utility company for review and comment. In Phase IV, the review comments from the utility companies and the NAPAP advisory committee were incorporated into the final 200-plant study report (4).

PERFORMANCE AND COST-ESTIMATING PROCEDURES

Figure 2 presents the cost-estimating methodology used to develop inputs to the Integrated Air Pollution Control System (IAPCS) cost model (5). For each plant, a boiler profile was developed based primarily on public information from Energy Information Administration Form 767, Powerplants Database (boiler design) (6), and aerial photographs obtained from state and federal agencies.

Low NO_x combustion (LNC) was evaluated for all dry-bottom boilers, with application of LNB on wall-fired units and OFA on tangential-fired units. NGR was evaluated for wet-bottom boilers and unconventional firing types because applying LNB was considered infeasible and OFA would not reduce emission rates sufficiently. Performance estimates were developed to account for non-ideal situations that will occur when retrofitting LNB and OFA. As discussed below, the NO_x reduction estimates are based on the boiler volumetric heat release rate. No cost adjustments were made to reflect site-specific situations. For NGR, a NO_x reduction of 60% was assumed for all boilers.

SCR was evaluated for all boilers with two types of SCR systems considered: hot-side and cold-side. Both configurations have wide commercial application in Japan and Germany. During the course of this study, very limited data were available on the long-term performance of hot-side systems on coal-fired applications, and no commercial or recent pilot scale data were available for hot-side systems using U.S. coal. Therefore, cold-side SCR systems were selected for most boilers.

Cold-side SCR systems are located downstream of particulate and SO_2 control systems, thereby reducing or eliminating the catalyst poisoning effects of sulfur (SO_3), chlorides, arsenic, and alkali metals, which are found to a higher degree in U.S. coals than in coals used overseas. The cold-side system configuration also minimizes unit downtime and replacement power costs, and facilitates combining smaller units into one system, thereby allowing economy-of-scale benefits. A disadvantage of cold-side systems is that the catalytic reactor is located after the air heater, so that the flue gas must be reheated to 650-700°F. However, the capital and energy costs associated with flue gas reheat are somewhat offset by lower catalyst costs.

Hot-side SCR systems require that the catalyst reactor be located in the flue gas path between the economizer and the air heater to take advantage of the high flue gas temperature (650-700°F), but because of the lack of data mentioned above, hot-side systems were applied only to boilers with hot ESPs or where space constraints prohibited the use of a cold-side system.

Low NO_x Burners and Overfire Air

When applying combustion controls, many boiler and coal parameters affect uncontrolled NO_x emissions and achievable NO_x reductions. However, accurate data for most of these parameters are not available. Additionally, well documented data on the performance of LNC retrofits on U.S. boilers are limited. After a review of the detailed procedures used to estimate NO_x reduction performance at 12 plants where site visits were conducted, boiler volumetric heat release rate was chosen to estimate NO_x reduction performance. For most boilers, furnace volume information was found in Powerplants Database. Based on data from four LNB retrofits, the following correlation was developed expressing NO_x emission reduction as a function of boiler furnace volume and unit power generation (2):

$$NO_xEFF = 68.8 * (V/MW) \qquad (A)$$

where: NO_xEFF = NO_x removal efficiency (percent)
V = Furnace volume (1000 ft^3)
MW = Boiler rating (megawatts)

Although this equation can yield NO_x reduction values lower than 25% and greater than 55%, 25 and 55% were used as lower and upper limits in this study.

If the furnace volume was not known, the following equations relating furnace volume to boiler rating were used for boilers constructed before (Equation B) and after (Equation C) the 1971 New Source Performance Standards (NSPS) (2):

For boilers constructed before the 1971 NSPS, $V = 0.596 * MW$ (B)

For boilers constructed after the 1971 NSPS, $V = 0.844 * MW$ (C)

Therefore, substituting either Equation B or C into Equation A for furnace volume gives roughly 40% NO_x removal efficiency for wall-fired boilers constructed before the NSPS was promulgated and roughly 55% NO_x removal efficiency for wall-fired boilers constructed after the NSPS promulgation.

Even less data were available on NO_x reductions that can be achieved when retrofitting OFA on tangential-fired boilers. A review of furnace volume data for tangential-fired boilers showed that the furnace volumes for pre-NSPS boilers are 40% smaller than the post-NSPS boilers. OFA is generally capable of achieving a 15 to 35% NO_x reduction (7). It was assumed that OFA can reduce uncontrolled NO_x emissions by 35% for tangential boilers that were in service after 1974 or that had furnace volumes similar to post-NSPS boilers. For boilers in service before 1974, a NO_x emission reduction of 25% was assumed. For boilers firing coals with high slagging tendencies, NO_x emission reductions were reduced by 5% (i.e., 25 - 5 = 20).

Natural Gas Reburning

NGR is included in this analysis, although it is not as commercially developed as the other NO_x control technologies. Including NGR in the study provides a moderate NO_x control level (relative to SCR) where LNBs are inapplicable (cyclone furnaces, slagging wall-fired units, unusual firing types. The NO_x reduction performance of NGR would be affected by some of the same factors discussed previously for LNC.

The Gas Research Institute is hoping to achieve NO_x reductions as high as 75% on high-NO_x-emitting boiler types. However, because of the lack of commercial demonstration performance data, a single estimate of 60% NO_x reduction was used in this study. To achieve 60% NO_x reduction, it was assumed that 15% of the boiler heat input would be injected into the upper furnace as natural gas. Capital costs include the installation of natural gas and OFA injection ports into the upper furnace, reburn gas supply piping, and controls.

Selective Catalytic Reduction

The major equipment items for an SCR system include the catalyst, ammonia system, controls, air preheater modifications or flue gas reheater, ductwork, and fan. The catalyst volume is based on the flue gas flow rate and an 80% NO_x reduction. The SCR equipment cost estimates were developed from EPRI (8) and EPA (9) studies.

The IAPCS cost algorithms are based on new unit installation. In order to adjust these costs for specific retrofit situations, scope adders (additional equipment costs) and retrofit factors (difficulty multipliers) were used to adjust the costs. Scope adder costs considered were:

- duct and building demolition,
- new duct work,
- new roads and replacement and demolished facilities, and
- new air heater (hot-side) or flue gas reheater (cold-side).

The EPRI flue gas desulfurization (FGD) retrofit guidelines (10) were used to develop costs for the first three items. New roads and replacement of facilities were handled as increases in general facilities. New air heater and flue gas reheater costs are based on a vendor quote for a 500-MW plant and scaled by a 0.6 factor (9).

Access/congestion and underground obstruction factors were applied to the catalytic reactor area. The EPRI FGD retrofit guideline factors for the SO_2 and flue gas handling area were used. The scope adjustments and retrofit difficulty factor were input to the IAPCS model to generate the site-specific retrofit cost estimates.

IAPCS COST MODEL RESULTS

The site-specific model inputs developed for each NO_x control technology were input to the IAPCS cost model, along with other boiler and coal characteristics. The model generated capital, operating and maintenance, and levelized annual costs of control and emission reductions. Table 1 summarizes the economic bases used to develop the cost estimates. Economic assumptions such as inflation rate, cost of money, cost of consumables, and expected plant life are from the 1986 EPRI Technical Assessment Guide (11) escalated to 1988 dollars.

For each control technology, cost per ton of NO_x removed (Figures 3 and 5) and annual cost (Figures 4 and 6) are plotted versus the sum of controlled megawatts. In each figure, the x-axis (sum of megawatts) is the cumulative sum of the boiler size sorted in order from the lowest to the highest cost to control. Also identified on each curve are the 25, 50, and 75 sum of megawatt percent points for the boilers included in the figures. Each point on the curves represents a specific boiler cost result. The first point represents the boiler that had the lowest cost. The last point represents the boiler that had the highest cost. The curves turn up sharply because each curve was developed starting with the boiler having the lowest control cost and ended with the boiler have the highest control cost. The cost results do not represent the average or cumulative cost of control.

Costs developed in this report are based on economic assumptions that may not represent a particular utility company's economic guidelines. The cost results are static (not dynamic) and represent a single year (1985 base year or another year specified by the individual utility company) with regard to capacity factor, coal sulfur, and pollution control characteristics.

Low NO_x Combustion Cost Results

Figures 3 and 4 summarize the unit cost and the annual cost, respectively, of retrofitting LNB at 228 boilers, OFA at 214 boilers, and NGR at 81 boilers. In general, boilers having low unit costs and annual costs are large, and have high capacity factors and high NO_x reduction efficiencies. Boilers having high unit costs and annual costs are small and have low capacity factors and low NO_x reduction efficiencies.

LNB were applied to wall-fired dry-bottom boilers. The boiler characteristics of the low, mid, and high unit cost are:

	Low $/ton	Mid $/ton	High $/ton
NO_x Unit Cost - $/ton	50	150	1315
Boiler size - MW	1000	640	45
NO_x Reduction - %	53	43	40
Capacity Factor - %	83	48	28
NO_x Removed - tons/yr	15828	4586	183

Of the 228 boilers, 16% were estimated to have high (45 to 55%) NO_x reduction efficiencies; 61% were estimated to have moderate (35 to 45%) NO_x reduction efficiencies; and 23% were estimated to have low (25 to 35%) NO_x reduction efficiencies.

OFA controls were applied to tangential-fired boilers. The boiler characteristics of the low, mid, and high unit cost are:

	Low $/ton	Mid $/ton	High $/ton
NO_x Unit Cost - $/ton	27	100	1248
Boiler size - MW	865	350	29
NO_x Reduction - %	35	25	25
Capacity Factor - %	79	56	18
NO_x Removed - tons/yr	6895	1271	39

Of the 214 boilers, 4% were estimated to have high (26 to 35%) NO_x reduction efficiencies; 73% were estimated to have moderate (25%) NO_x reduction efficiencies; and 23% were estimated to have low (15 to 24%) NO_x reduction efficiencies.

NGR controls were applied to wet-bottom boilers and boilers having unusual firing types (e.g., roof-fired). The cost of NGR is much greater than LNB and OFA because of the fuel price differential between natural gas and coal. The cost results presented here are based on a fuel price differential of $2 per million Btu and 15% natural gas substitutes. Reducing the fuel price to $1 per million Btu reduces the unit cost by ~50%. Not included in the unit cost is the benefit of the 15% reduction in SO_2 due to the 15% fuel substitution. If the SO_2 reduction were included in the unit costs, the unit cost of NGR would be reduced by 15 to 45 percent.

Selective Catalytic Reduction Cost Results

In this study, cost estimates for SCR were developed for 624 boilers: 577 boilers with cold-side systems and 47 boilers with hot-side systems. Figures 5 and 6 summarize the cost estimates for application of SCR. For cold-side systems, a significant energy penalty occurs with flue gas reheating, (equivalent to 120°F reheat). This cost was not included in this study because the earlier version of the IAPCS model did not estimate this cost. Reheat costs estimated by the most recent version of IAPCS (12) increase the annual cost of control by 20 to 30% for cold-side systems.

Costs presented here are for a 3-year catalyst life. However, clean gas applications of SCR may have much longer catalyst life. Annual and unit costs estimated for a 7-year catalyst life are 10 to 20% less than those with 3-year catalyst life.

For SCR, the boiler characteristics of the low, mid, and high unit cost are:

	Low $/ton	Mid $/ton	High $/ton
NO_x Unit Cost - $/ton	710	1810	6091
Boiler size - MW	217	543	45
NO_x Reduction - %	80	80	80
Capacity Factor - %	94	49	28
NO_x Removed - tons/yr	10,546	8331	366

CONCLUSION

There is a high degree of uncertainty regarding the cost and performance of retrofitting NO_x controls on U.S. boilers because of the very limited commercial application experience. Passage of the Clean Air Act Amendments of 1990 require that NO_x emissions from wall- and tangential-fired boilers meet NO_x emission limits of 0.5 and 0.45 pounds per million Btu by applying LNB. These emission limits do not apply to cell-fired and wet-bottom boilers. The results of this study show that the application of LNB and OFA are likely to have a wide range of effectiveness for retrofit applications. As result, it can be expected that many units may have difficulty achieving emission limits of 0.5 and 0.45 pounds per million Btu through the application of LNB and OFA. The study results and study database can provide guidance in evaluating the effectiveness of retrofitting LNC controls, but because of the complexities of combustion modification controls the results of this study could vary widely from the NO_x reductions that can be achieved in practice.

REFERENCES

1. Emmel, T. E., S. D. Piccot, and B. A. Laseke. Ohio/Kentucky/TVA Coal-Fired Utility SO_2 and NO_x Control Retrofit Study. EPA-600/7-88/014 (NTIS PB88-244447/AS), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, 1988.

2. Smith, L. L., Energy Technology Consultants, Inc. Evaluation of Radian/EPA NO_x Reduction Estimation Procedures. Radian Corporation, Research Triangle Park, North Carolina, 27709. February 1988.

3. Emmel, T.E., et al. Comparison of West German and U.S. Flue Gas Desulfurization and Selective Catalytic Reduction Costs. EPA-600/7-90-009, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711. April 1990.

4. Emmel, T. E., and M. Maibodi. Retrofit Costs for SO_2 and NO_x Control Options at 200 Coal-Fired Plants. EPA-600/7-90-021a, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711. November 1990.

5. Palmisano, P. J., and B. A. Laseke. User's Manual for the Integrated Air Pollution Control System Design and Cost Estimating Mode, Version II, Volume I. EPA-600/8-86/031a (NTIS PB87-127767), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, 1986.

6. Elliot, T. C., ed. Powerplants Database, Details of the Equipment and Systems in Utility and Industrial Powerplants, 1950-1984. McGraw-Hill, Inc., New York, New York, 1985.

7. Thompson, R. E., and M. W. McElroy. Guidelines for Retrofit Low NO_x Combustion Control. In Proceedings: 1985 Symposium on Stationary Combustion NO_x Control, Volume 1, EPA-600/9-86-021a (NTIS PB86-225042), July 1986.

8. Bauer, T. K., and P. G. Spendle. Selective Catalytic Reduction for Coal-Fired Power Plants: Feasibility and Economics. EPRI CS-3603, Electric Power Research Institute, Palo Alto, California, 1984.

9. Burke, J. M., and K. L. Johnson. Ammonium Sulfate and Bisulfate Formation in Air Preheaters. EPA-600/7-82-025a (NTIS PB82-237025), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, 1982.

10. Shattuck, D. M., et al. Retrofit FGD Cost Estimating Guidelines. EPRI Report CS-3696, Electric Power Research Institute, Palo Alto, California, 1984.

11. Electric Power Research Institute. Technical Assessment Guide (TAG), Volume 1. Electricity Supply--1986. EPRI Report P-4463-SR, Palo Alto, California, 1986.

12. Maibodi. M, et al. Integrated Air Pollution Control System, Version 4.0, Volume 2: Technical Documentation Manual. EPA-600/7-900-022b, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711. December 1990.

Table 1.

ECONOMIC BASES USED TO DEVELOP THE COST ESTIMATES

Item	Value
Operating labor	19.7 $/person-hour
Natural gas to coal fuel price difference	$2/million Btu
Electric Power	0.05 $/kWh
Catalyst cost	20,290 $/ton
1988 constant dollar levelization factors	
Operating and maintenance	1.0
Capital carrying charges[a]	0.105

[a] Book life - 30 years; Tax life - 20 years; Depreciation Method - Straight Line; and Discount Rate - 6.1%.

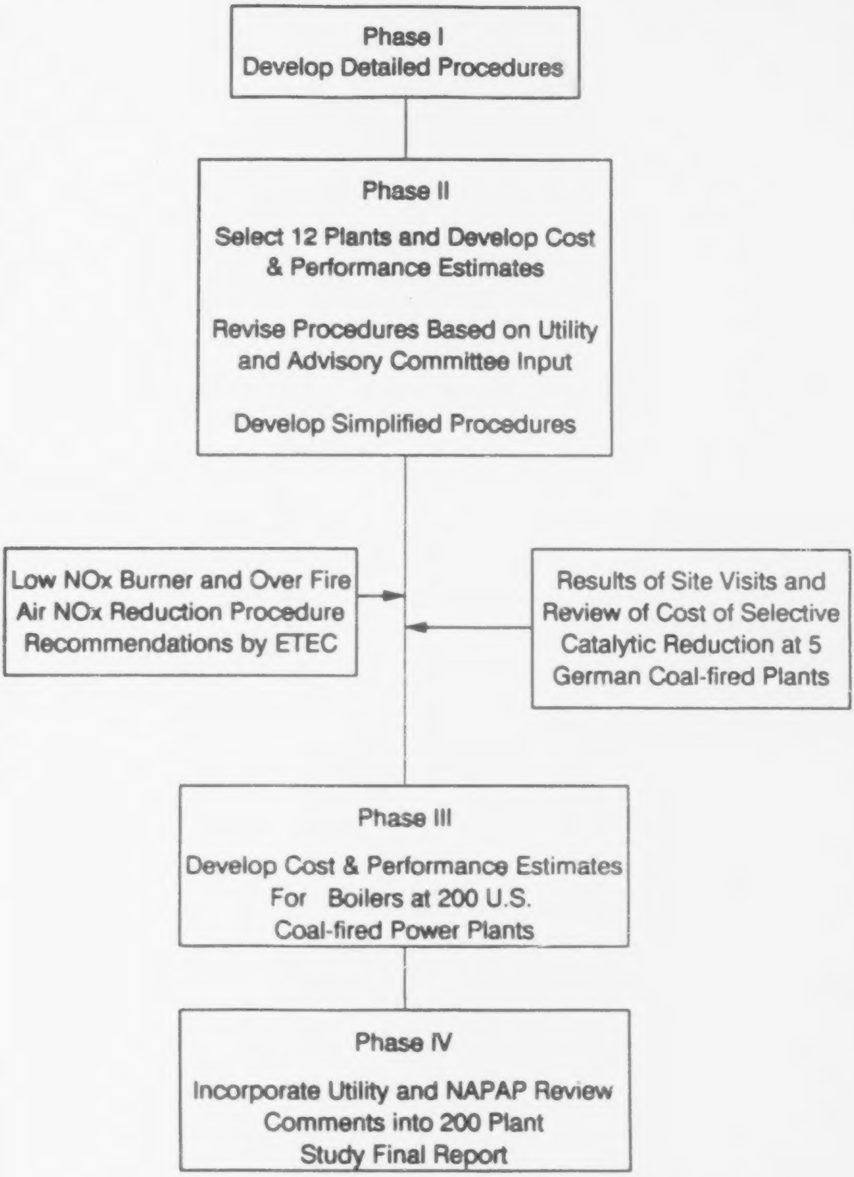

Phase I
Develop Detailed Procedures
Phase II
Select 12 Plants and Develop Cost & Performance Estimates
Revise Procedures Based on Utility and Advisory Committee Input
Develop Simplified Procedures
Low NOx Burner and Over Fire Air NOx Reduction Procedure Recommendations by ETEC
Results of Site Visits and Review of Cost of Selective Catalytic Reduction at 5 German Coal-fired Plants
Phase III
Develop Cost & Performance Estimates For Boilers at 200 U.S. Coal-fired Power Plants
Phase IV
Incorporate Utility and NAPAP Review Comments into 200 Plant Study Final Report

FIGURE 1. 200 PLANT STUDY TECHNICAL APPROACH.

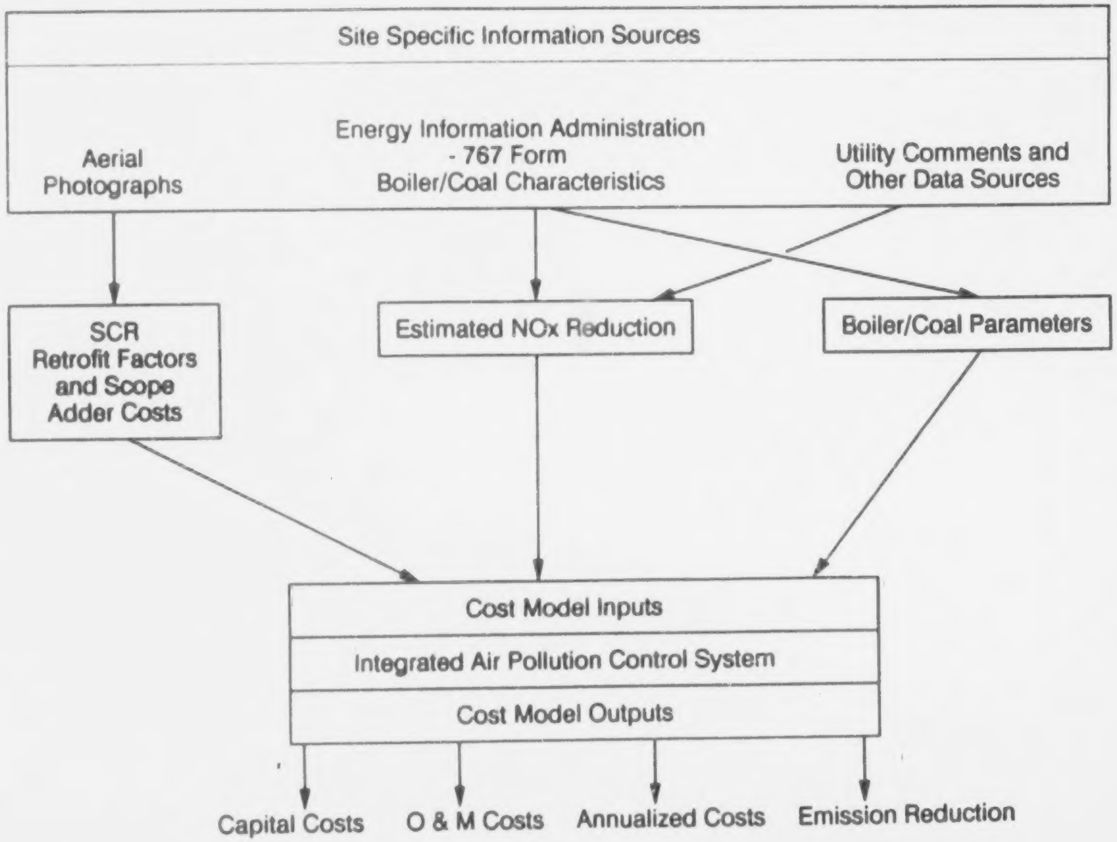

Site Specific Information Sources
Aerial Photographs
Energy Information Administration - 767 Form Boiler/Coal Characteristics
Utility Comments and Other Data Sources
SCR Retrofit Factors and Scope Adder Costs
Estimated NOx Reduction
Boiler/Coal Parameters
Cost Model Inputs
Integrated Air Pollution Control System
Cost Model Outputs
Capital Costs
O & M Costs
Annualized Costs
Emission Reduction

FIGURE 2. SITE-SPECIFIC COST ESTIMATION METHODOLOGY.

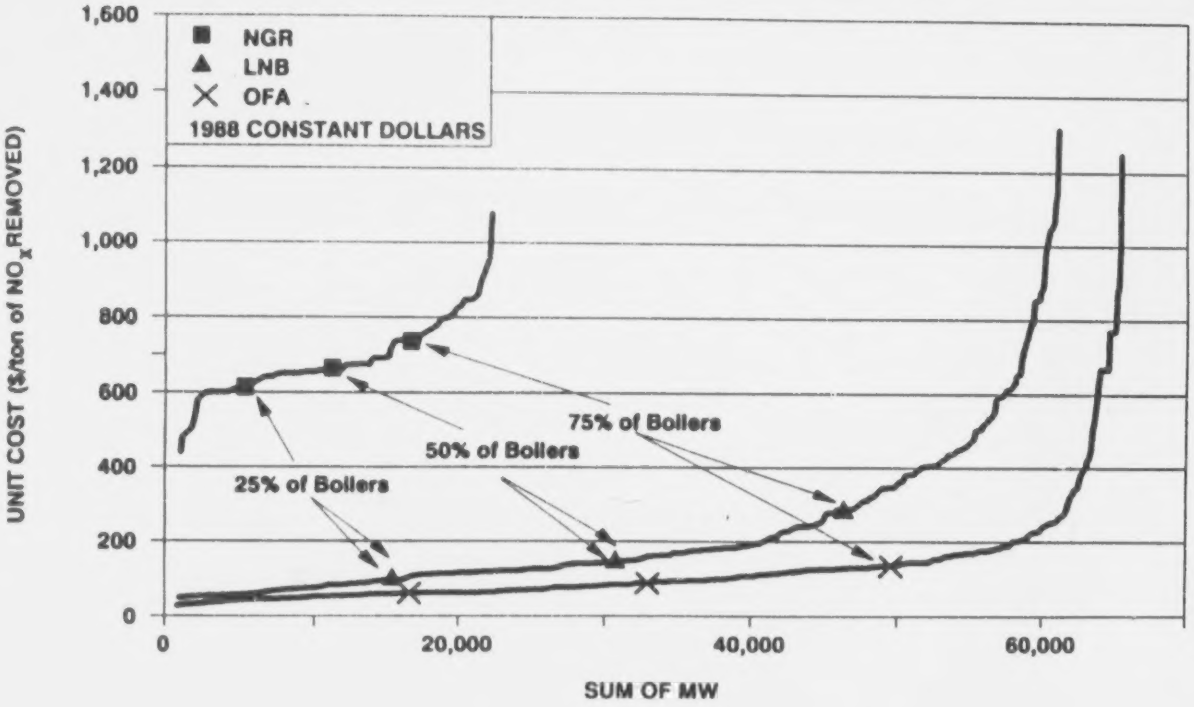


FIGURE 3. SUMMARY OF COST PER TON OF NOx REMOVED RESULTS FOR LOW NOx COMBUSTION.

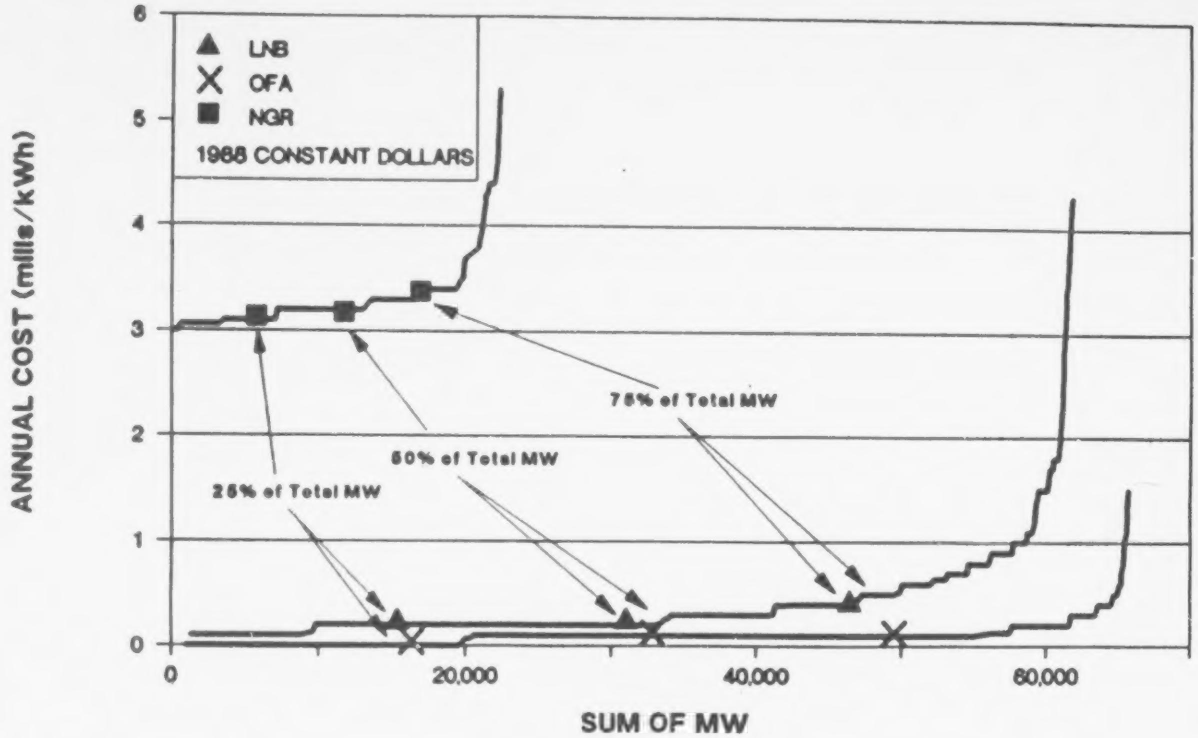


FIGURE 4. SUMMARY OF ANNUAL COST RESULTS FOR LOW NOx COMBUSTION

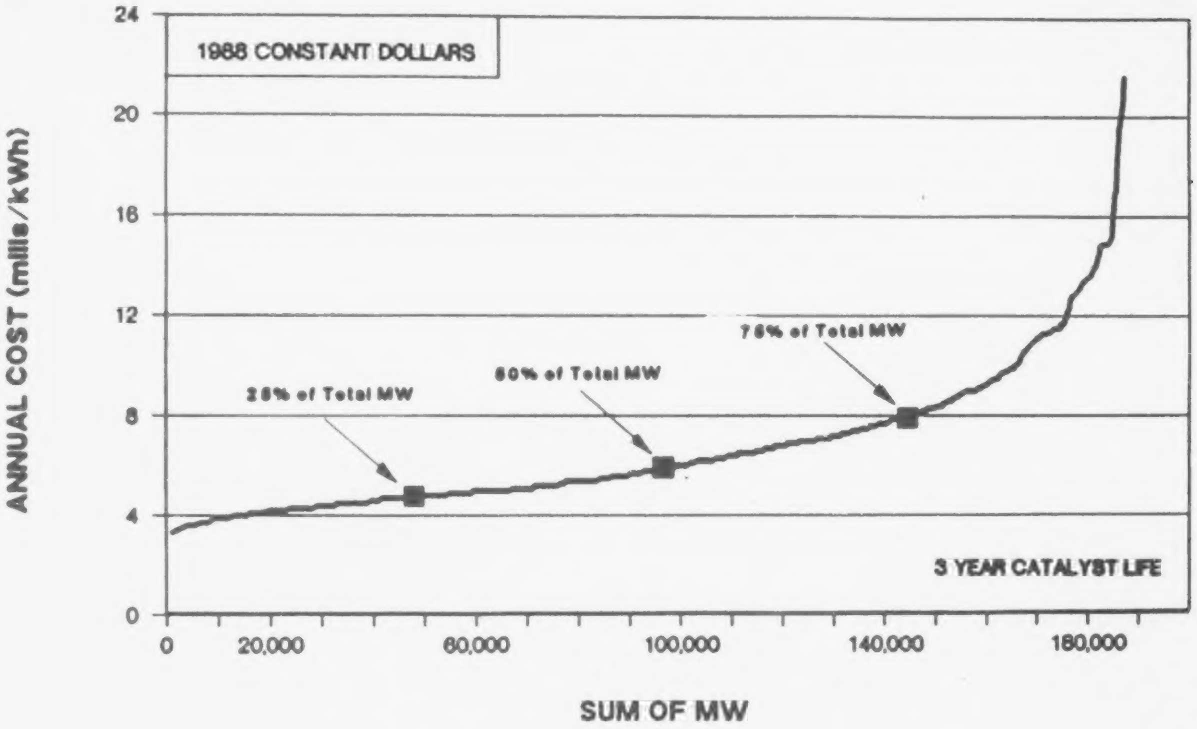


FIGURE 5. SUMMARY OF ANNUAL COST RESULTS FOR SELECTIVE CATALYTIC REDUCTION.

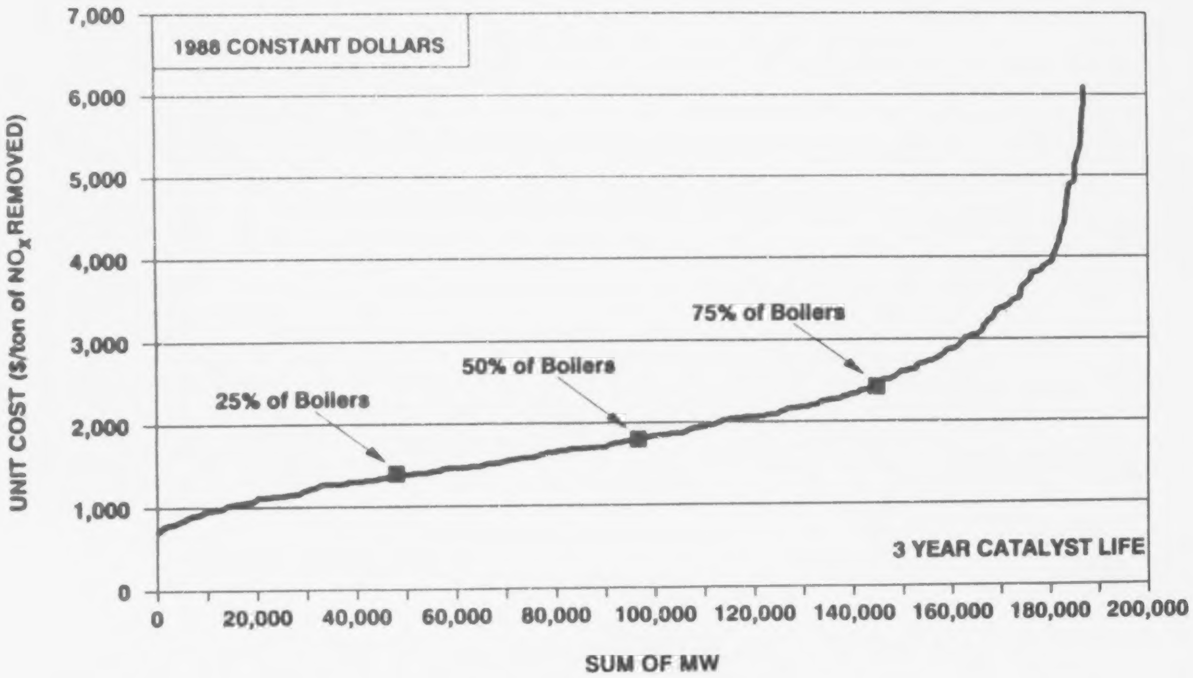


FIGURE 6. SUMMARY OF COST PER TON OF NOx REMOVED RESULTS FOR SELECTIVE CATALYTIC REDUCTION.

Attachment 5

EPRI
Electric Power
Research Institute
Leadership in Science and Technology

August 1, 1990

The Honorable Quentin Burdick
Chairman, Senate Environment and
Public Works Committee
United States Senate
511 Senate Hart Building
2nd and C Streets, N.E.
Washington, D.C. 20510

Dear Mr. Chairman:

I have noted with interest the evolution of Clean Air Act Amendment legislation under your leadership over the last several months. Your personal efforts in moving this forward have been noteworthy, and I support the concept of environmental improvements; indeed much of the Electric Power Research Institute's (EPRI's) work follows this premise. However, I find that certain wording attributed to EPRI in Committee Report 101-228 on S.1630, The Clean Air Act Amendments of 1989, is not consistent with EPRI's view of the use of selective catalytic reduction (SCR) technology to reduce NO_x emissions.

The Committee Report and EPRI's assessment differ in two key areas:

- SCR technical feasibility for domestic medium and high sulfur coal, and

- Control costs on a levelized $/ton basis.

Although SCR has been applied extensively internationally, the low coal sulfur content typifying Japanese and European applications (0.4% and 1%, respectively) provides significantly different process conditions from potential U.S. applications. Uncertainty about the success and cost of U.S. applications stems from possible corrosion and ash adhesion problems induced by sulfur-based acids, the potential for early loss of catalyst activity due to certain minerals in domestic coal ash, and byproducts created by the SCR catalyst. EPRI-funded fundamental research to study SCR catalyst poisoning mechanisms shows that certain sulfur-containing compounds and selected halogens , alkali, and heavy metals can all be strong poisons. For

U.S. boilers fired by medium and high sulfur fuels, high concentrations of these constituents in the flue gas would reduce NO_x conversion efficiency and shorten useful catalyst life. This is very significant since the cost of catalyst replacement is one of the largest influences on $/ton removed computations. The dramatic influence of coal quality and its effect on SCR catalyst was originally examined in the U.S. by EPA at Georgia Power's Plant Mitchell in the early 1980's with Japanese SCR technology. That project was not notably successful. To quantify these effects more definitively, using the latest catalysts, the DOE is supplementing EPRI's research on SCR exposed to domestic coal-produced flue gas with a project under its Clean Coal Technology initiative.

So, while Japanese and European experience with low sulfur coal may suggest that 4 year lifetimes can be achieved, medium/high sulfur U.S. fuels may enjoy a much briefer effective life cycle. It would, therefore, seem inappropriate to predict unqualified success of Japanese or European SCR technology in this country on fuel gas from domestic fuels.

It is also inappropriate to use $600/ton of NO_x removed as an SCR retrofit cost estimate (pg 297). Recent EPRI engineering studies project retrofit SCR costs for high sulfur coal-fired boilers to be nominally $100/kW, with levelized removal costs of $2,500 to $5,500/ton-- 4 to 9 times the Committee Report estimates even under the best commercial conditions that can be achieved today. The $600/ton cost cited in the Committee Report and attributed to EPRI estimation methods could only be described as a research target and would require several technical breakthroughs in SCR catalyst performance and process design. It would also probably be associated with installing SCR on boilers such as cyclones that emit very high levels of NO_x and cannot be controlled by burner modification. In most other cases we expect that SCR would be installed in conjunction with low NO_x burners, and the cost of the incremental NO_x removed would be much higher. The Committee Report also cites SCR as comprising 3-4% of total plant levelized cost (Figure IV-17, pg. 299) from a Japanese study of U.S. SCR costs. EPRI estimates, in contrast, that account for the effect of SCR on all plant components, show the addition of SCR increases new plant cost by 8-10%. German utilities have given us similar figures.

In summary, there are significant concerns regarding the application of SCR to medium and high sulfur domestic coal-fired boilers. The favorable reports of SCR application in Japan and Europe are not directly applicable to U.S. conditions due to the exclusive use of low sulfur fuels overseas. EPA's work in the 1980's clearly demonstrated this. EPRI cost estimates for SCR retrofit to existing high sulfur coal-fired boilers are \$2500-5500/ton NO_x removed, and SCR as described has not been shown to provide "reliable and economic operation in a wide range of conditions" as quoted in the Committee report.

Thank you for the opportunity to clarify EPRI's view of selective catalytic reduction (SCR) technology for NO_x removal. If the Electric Power Research Institute or I can be of further assistance, please do not hesitate to call.

Very truly yours,

Kurt Yeager

Kurt E. Yeager
Vice President
Generation & Storage Division

KEY.9913.L/bd

cc: Honorable Daniel Moynihan
Honorable George Mitchell
Honorable Max Baucus
Honorable Frank Lautenberg
Honorable John Breaux
Honorable Harry Reid
Honorable Bob Graham
Honorable Joe Lieberman
Honorable John Chafee
Honorable Alan Simpson
Honorable Steve Symms
Honorable Dave Durenberger
Honorable John Warner
Honorable James Jeffords
Honorable Gordon Humphrey

Appendix II—Additional Material Submitted for the Record

American Paper Institute, Inc.
1250 Connecticut Ave., N.W., Suite 210, Washington, DC 20036
(202) 463-2420

April 1, 1991

The Honorable J. Bennett Johnston
Chairman
Senate Committee on Energy
and Natural Resources
Washington, D.C. 20510

Dear Mr. Chairman:

The American paper Institute is the national trade association of companies that manufacture pulp, paper and paperboard in the United States. As an energy intensive industry, we have views on a number of issues included in S. 341, some of which we have already submitted to the Committee.

Enclosed is an additional statement of the American Paper Institute on Section 5101 of S. 341 which we hope you will include in the hearing record of March 18, 1991.

This letter of transmittal need not appear in the record. Thank you very much.

Sincerely,

John W. Rauber, Jr.

John W. Rauber, Jr.
Director
Legislative Affairs

Enclosure
Ltr0401.Joh

bcc: Don Santa

Paper Industry USA
300 Years of Progress
1690-1990

Comments of the American Paper Institute, Inc. on Section 5101 of S 341, The "WEPCo" Provisions

The American Paper Institute (API) appreciates the opportunity to submit its views to the Senate Committee on Energy and Natural Resources on Section 5101 of S 341, The National Energy and Security Act. API is the national trade association of the pulp and paper industry, with over 175 member companies representing more than 90 percent of the manufacturing capacity of pulp, paper and paperboard in the United States.

API supports the intent of Section 5101 of S 341, which addresses the so-called "WEPCo" problem -- EPA's policy of defining "major modifications" of air pollution sources extremely broadly. Under EPA's approach in recent years, changes in electric generating stations and other sources, whether for purposes of improving efficiency and reliability, repairing aging equipment, or even adding pollution control equipment or switching fuels, may be subject to strict requirements for new sources, even if emissions from the source will actually be lower. API's member companies are concerned about the limited reach of Section 5101: it deals only with a small portion of the WEPCo problem (disincentives for pollution control), and even then only addresses the concerns of electric utilities.

Industrial facilities, such as pulp and paper mills, operate thousands of boilers which generate substantial amounts of both process steam and electricity. Furthermore, these facilities are a significant source of electricity and a major component of the nation's energy supply mix. Other process equipment are significant users of electricity and fossil fuels. It is very important that both electricity-producing and energy-consuming equipment at industrial facilities not be saddled by the "WEPCo" disincentives to efficiency or operability improvements, no more so than electric utility units. Further modifications to S 341 are needed to assure that Section 5101 deals fully with the barriers that the current WEPCo policy presents to energy production and conservation in all sectors of the economy.

STATEMENT OF
THE AMERICAN GAS ASSOCIATION
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
ON SEC. 5101 OF S. 341
APPLICABILITY OF NEW SOURCE REVIEW
TO EXISTING ELECTRIC UTILITY
STEAM GENERATING UNITS

March 18, 1991

- -

Mr. Chairman and members of the Committee: The American Gas Association (A.G.A.) is a national trade association comprising some 250 natural gas distribution and transmission companies serving over 174 million natural gas consumers throughout the United States. As an industry whose fuel is used for electric generation, A.G.A. is pleased to see the inclusion of a section on applicability of New Source Review to existing electric utility steam generating units in S. 341, the National Energy Security Act of 1991.

The Issue

EPA's decision in the "WEPCO" case and the subsequent court decision[1] treat certain physical and operational alterations of existing power plants as modifications that trigger the application of New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) review pursuant to Section 111 and parts C and D of the Clean Air Act. This policy inhibits the electric utility industry's ability to meet the nation's growing electricity needs and the requirements of the Clean Air Act in a cost-effective, reliable and environmentally rational manner. Moreover, the WEPCO decision can be applied to any existing stationary source that undergoes a modification. A.G.A.'s membership includes combination electric and gas companies who may be faced with NSPS or PSD, but our interest lies primarily with the effect of the WEPCO decision on the ability to cofire natural gas with coal at existing electric generating plants, industrial, and cogeneration units.

---

[1] Wisconsin Electric Power Company v. Reilly, 893 F.2d 901 (7th Cir. 1990)

EPA's WEPCO decision undermines the flexible, freedom of choice principle espoused by Congress in the Clean Air Act Amendments of 1990. Title IV of the Act sets SO_2 emissions limitations for existing electric generating units, and other units that opt-in to the program. It does not prescribe a method for controlling emissions, thereby allowing operators to make the most efficient choices for their units. However, if the WEPCO decision is not modified, installing cofiring equipment for SO_2 control could trigger onerous NSPS/PSD review, while installing scrubbers may not. It is our concern that most electric generators would install scrubbers to comply with the Clean Air Act, thereby sacrificing energy efficiency and increasing CO_2 to avoid NSPS/PSD review. Additionally, the WEPCO decision has a very chilling effect on industrial SO_2 emitters' willingness to opt-in to the acid rain allowance program.

Recommendations

We are pleased that S. 341 incorporates a provision to address the WEPCO problem. We believe it is appropriate for an energy security bill to address this issue. A legislative solution that results in greater efficiencies, lower operating costs and decreased emissions, is good public policy that will help to enhance our nation's energy security and lessen our dependence on foreign oil. By facilitating the use of gas as a control option, such as in cofiring natural gas with coal, S. 341 will help to increase the efficient use of our nation's two most abundant natural resources.

Sec. 5101(a) suggests that a switch to natural gas or clean coal technologies would need to be undertaken for the purpose of pollution control. A.G.A. believes that electric steam generating units switching to lower emission fuels should be excluded under WEPCO for other reasons in addition to a switch for pollution control. The switch may be, for example, for more unit efficiency with the added benefit of lower emissions. Sec. 5101(b)(1)(B) has the effect of requiring NO_x control technology that does not yet exist or is too expensive for certain boilers. This subsection goes far beyond the Clean Air Act and has questionable energy security and efficiency value. We, therefore, urge you to revise Section 5101 to incorporate the following technical changes --

Sec. 5101. APPLICABILITY OF NEW SOURCE REVIEW TO EXISTING ELECTRIC UTILITY STEAM GENERATING UNITS. -- (a) POLLUTION CONTROL PROJECTS. --

For purposes of the Clean Air Act, no physical change in, or change in the method of operation of an electric utility steam generating unit, ~~which is undertaken for purposes of pollution control~~ including the use of natural gas ~~and~~ or clean coal technologies, shall be treated as a modification for a specific regulated pollutant for purposes of part C or D of title I of the Clean Air Act if such change does not increase the potential emissions of the specific regulated pollutant from such source above the potential emissions before the change.

(b) NITROGEN OXIDE CONTROL REQUIREMENTS. -- . . . (1)(B) For an existing utility steam generating unit not subject to section 407 of the Clean Air Act immediately following the modification, the unit shall be required to meet the nitrogen oxide limit ~~equivalent to the limit achievable using "low NO_x burners."~~ as established by EPA in accordance with the Clean Air Act Amendments of 1990.[*]

---

[*] Underlined words represent additional words and strikeovers represent deletions.

While Sec. 5101 of the bill will alleviate most of the burden of the WEPCO decision on electric steam generating units, A.G.A. is very concerned that EPA will apply the WEPCO decision to major stationary sources other than electric steam generating units. Among other things, this will discourage these other sources, such as industrial and cogeneration sources from making oil-to-gas conversions, thereby frustrating the acid rain emissions trading scheme. In addition, the WEPCO decision may affect our ability to get the natural gas to these fuel switching facilities by imposing overly restrictive regulations on existing facilities that are used to respond to any new natural gas supply requirements.

Since the WEPCO decision could apply to sources other than electric steam generating units, A.G.A. supports any consideration for a broader WEPCO "fix" that would prevent overly restrictive regulations on sources using or proposing to use clean-burning natural gas. These suggested changes have the effect of promoting operating and economic efficiencies in addition to lowering emissions of harmful pollutants, making it a "win-win" situation for energy security and environmental protection.

In this same regard, we believe S. 341 should include general provisions that address the benefits derived from using clean burning, domestic fuels. The legislation should require EPA and DOE to look at the ultimate use of gas by the end-user, and the energy security and net environmental benefits derived, when promulgating rules that address a broad spectrum of issues. We suggest that S. 341 encourage regulatory agencies to avoid unnecessary duplicative regulatory requirements. Moreover, agencies should not erect roadblocks, which would ultimately inhibit natural gas from getting to the market where its energy security and net environmental benefits would outweigh any negative impacts early on. Some examples would be to impose stringent NO_x controls on compressor stations, duplicative regulation of underground storage tanks and regulation of oil and gas production waste under RCRA. We would be happy to discuss these issues further with this Committee as it continues deliberations on the bill.

We appreciate this opportunity to comment and believe that if this Committee incorporates our recommendations to the bill, the nation's energy security, air and energy efficiency will be enhanced.

APPENDIXES TO MARCH 19, 1991 HEARING

(Subtitle A of Title V)

Appendix I—Responses to Additional Questions

POST-HEARING QUESTIONS AND ANSWERS

ROBERT GENTILE
ASSISTANT SECRETARY FOR FOSSIL ENERGY
U.S. DEPARTMENT OF ENERGY

HEARING ON SUBTITLE A OF TITLE V
S.341, THE NATIONAL ENERGY SECURITY ACT OF 1991

MARCH 19, 1991

QUESTIONS FROM SENATOR FORD

Clean Coal Technology

Question 1: DOE is required by law to begin the Round 5 solicitation by March 1, 1992. DOE has proposed in its FY-92 budget request to eliminate, or delay, the initiation of Round 5.

a. Does the Department intend to submit legislation to Congress, separate from the FY-92 budget submittal, to delay the deadline for beginning Round 5?

b. What will the Department do if Congress fails to go along with the Administration's proposal to delay Round 5?

c. Will the Department be ready to begin Round 5 if Congress fails to acquiesce to a delay? Will the Department be able to meet the March 1, 1992 deadline?

d. Does the Department now have plans, or anticipate making plans, to submit a reprogramming request to Congress for use of funds appropriated for the clean coal program for either FY-91, FY-92, or FY-93?

Answer: The Department does not intend to submit separate legislation at this time. However, we would be willing to suggest appropriate legislative language, if requested by the Congress. If Congress does not modify the existing legislation, the Department can and will implement Round 5 by the March 1, 1992, deadline. The Department is currently evaluating the need for a reprogramming request. However, no decisions are expected on this matter prior to the summer of 1991.

QUESTIONS FROM SENATOR FORD

Clean Coal Technology

Question 2: **You said at the hearing that the Department would be willing to work with the Committee to develop appropriate provisions for incentives for clean coal technology. You indicated that these provisions might be similar to that included in the Administration's clean air legislation submitted to Congress in 1989.**

Would you be willing to provide to the Committee any analysis done by the Department on this either during preparation of the clean air legislation or during the development of the national energy strategy?

Answer: The incentives contained in the Administration's original clean air legislative proposal were based on two interagency efforts. The first was the Report of the Innovative Control Technology Advisory Panel (ICTAP Report). This report was the product of a panel that included representatives of various state governments (including state environmental officials), utilities, federal agencies (Commerce, Energy, EPA, OMB), and state regulators from Michigan and West Virginia. Attached is a copy of the report.

The second effort was an analysis prepared to support a rulemaking to mandate economic incentives for innovative pollution control technologies. (The rulemaking was abandoned in favor of the legislative proposals included in the President's Clean Air Proposal.) This analysis was an outgrowth of a March 1988 request by then Vice President Bush to develop such regulatory incentives, as part of a slate of

Committee Note--The material submitted has been retained in Committee files.

initiatives recommended by the President's Task Force on Regulatory Relief. We would be willing to share this draft proposed package as well.

QUESTIONS FROM SENATOR FORD

Clean Coal Technology

Question 3: You also indicated that the Department would be willing to work with the Committee on initiatives to eliminate or minimize regulatory barriers to deployment of clean coal technologies.

Again, would you be willing to provide to the Committee any analysis done by the Department on this either during preparation of the clean air legislation or during the development of the national energy strategy?

In your opinion, what are the regulatory barriers to commercial use of clean coal technologies?

Answer: The regulatory barriers to commercial use of clean coal technologies include:

(1) Rate regulation risks inherent in pre-commercial technologies; and

(2) The "WEPCo decision," which as currently applied creates uncertainty for some clean coal technologies with regard to what increased environmental requirements EPA may impose.

The answer to Question 2 addresses the barriers posed by rate regulation. Regarding the WEPCo decision, our hope is that the CAA Amendments signed into law last fall will take care of the problem for most clean coal technologies, e.g., temporary retrofits and permanent repowerings. The Administration is in the process of developing a comprehensive response to addressing the remaining issues associated with the WEPCo decision.

QUESTION FROM SENATOR FORD

Coal Provision of S. 341

Question 4:	You say that the coal-related priorities of the National Energy Strategy and the FY 92 budget are "generally consistent with title V." You also say that DOE's efforts in the clean coal program and coal R&D are consistent with section 5001. a) Is that really true, given the Department's decision to cancel--to delay, as you say-- Round 5 of the clean coal program? Please explain in detail.
Answer:	The National Energy Strategy (NES) recognizes the importance of coal and clean coal technologies in our energy mix. It recognizes that coal is readily available and priced competitively. But it also suggests that for coal to remain acceptable as a major energy source, it must be produced, transported, and used in ways that fully protect the environment. As a result, the NES' approach to assuring the competitiveness of coal is to implement the Research, Development, and Demonstration programs to develop advanced coal utilization technologies.

The FY 92 budget proposal provides the funding needed to advance most of the technologies that will support the continued use of coal beyond the year 2000. Specifically, the budget provides $115 million to:

- continue to reduce the cost of producing coal-derived transportation and boiler fuels (i.e., coal liquefaction, alternative fuels and coproducts)

- continue to develop high efficiency, low polluting advanced power generation systems (i.e., surface coal gasification power systems, pressurized fluidized bed combustion, fuel cells and gas stream cleanup)

- continue to develop low polluting pre-combustion and post-combustion cleanup options i.e., coal preparation, flue gas cleanup and waste management).

It is recognized that some programs are proposed to be terminated (i.e., MHD and heat engines) because of budget constraints. Some terminations reflect a desire to focus the program on activities that offer benefit to NES priorities. However, the programs included in the budget will ensure that a variety of important options are available in the future.

Regarding the Clean Coal Technology Demonstration Program, $315 million has been included to further fund Round 4. The budget also proposes support for the advanced appropriation needed to complete Round 4.

No money is required for Round 5 in FY 92 since project selections would not be before November 1992, the beginning of FY 93. Rather, it was proposed to reassess the timing and funding level for Round 5 as part of the FY 93 budget process.

QUESTIONS SUBMITTED BY SENATOR FORD

Coal Provision of S. 341

Question 4: **You say that the coal-related priorities of the National Energy Strategy and the FY-92 budget are "generally consistent with title V." You also say that DOE's efforts in the clean coal program and coal R&D are consistent with section 5001.**

b) Do your statements mean that you would support the provisions of title V?

c) Or, do you mean that you think the provisions are unnecessary because you believe DOE is already doing everything it needs to do?

Answer: DOE supports the intent of most sections of Title V. We believe that most of the provisions of Title V are already being conducted either in our R,D, &D program (Sections 5001, 5002, 5005, 5006) or our export initiative (Sections 5003 and 5004 if the focus is broader than coal and LDCs). We also support section 5008 if protection of confidential and business proprietary data is assured. We do not support the initiation of new activities to promote the non-fuel use of coal: it is not part of the Administration's National Energy Strategy. It is the view of DOE that new legislation is not required to implement any of the initiatives in Title V.

QUESTIONS FROM SENATOR FORD

Coal Provisions of S.341

Question 5: You state that you do not think a separate program is necessary in non-fuel uses of coal, such as proposed in section 5002. Yet, it seems to me that DOE is just at the beginning of its work in this area. Why wouldn't such a program, as proposed in section 5002, be appropriate?

Answer: Non-fuel use of coal is not a high priority in the President's National Energy Strategy. Nonetheless, some work is being done in that area, but it does not require special treatment such as legislative mandating. The existing coal R&D programs in mild gasification and indirect liquefaction presently address non-fuel uses of coal. Two of these technologies, mild gasification by ENCOAL and once-thru-methanol by Air Products and Chemical, Inc., were selected for funding in the Clean Coal Technology Program. Additional research under the Coal Preparation Program is being conducted at the University of Utah to develop a process for the selective flotation of fossil resin from western coal. The resins have industrial applications as printing ink, adhesives, paints and coatings, thermoplastics and may even be used as a high density jet fuel. Other projects have been, and will be, candidates for funding. Funding constraints require that priorities be established, and DOE has a balanced program which addresses these priorities.

QUESTIONS FROM SENATOR FORD

Coal Refining

Question 6: It was evident from your testimony that DOE has done very little comprehensive analysis of the potential for development of coal refining technologies. DOE is required by the FY 91 Interior Appropriations to assess coal refining concepts and report to Congress in July 1991.

a. What coal refining concepts will be discussed in that report?
b. Has DOE drawn any conclusion yet in its efforts to prepare this report?
c. Will the report be comprehensive in its evaluation of all known coal refining concepts?

Answer:

a. To date, approximately 30 concepts have been identified for consideration in the final report. After screening such items as environmental issues, economics, R&D needs and applications, the most promising eight to ten concepts will be determined for inclusion in the final report with complete descriptions and analysis.
b. No conclusions have been drawn. Since this effort has only recently been initiated, it is premature to draw conclusions. However, as mentioned above, several different definitions or concepts of the coal refinery are under review.
c. To the best of our ability, given the time and funding constraints that prevail, the report will be comprehensive in its evaluation of coal refinery concepts.

QUESTIONS FROM SENATOR FORD

Coal Refining

Question 7:	What amount of federal dollars are now put toward coal refining technologies?
Answer:	There is wide flexibility in the definition of "coal refinery" or "coal refining" technologies. In its broadest, most general sense, it could be defined as technology which produces liquids, gases, solids, and electricity, or a slate of these products from coal (some of which could serve as feedstocks to oil refineries to provide petrochemicals). The amount of federal dollars in the FY 1991 budget appropriated for efforts in support of this broad definition of "coal refining technologies" is listed below:

Direct Liquefaction	$20,509,000
Indirect Liquefaction	11,859,000
Liquefaction Support	2,263,000
Coproducts (or Mild Gasification)	6,165,000
Synthesis Gas	1,039,000
TOTAL	$41,835,000

QUESTIONS FROM SENATOR FORD

Coal Refining

Question 8: Shouldn't DOE be investing more money in coal refining technology? Wouldn't this fit into the definition of higher-risk R&D, hence being an appropriate area of work for DOE to pursue?

Answer: The DOE request in "coal refining technology" for FY 1992 is considered adequate and appropriate based on present funding limitations and program priorities. The "coal refinery technology" is at various stages of development. The ENCOAL Clean Coal III project is at the large-scale demonstration stage with relatively little R&D risk remaining. By comparison, some of the more recent mild gasification processes now under development at the small scale of 100 pound per hour have considerably higher risk associated with scaleup R&D required to advance to the "proof-of-concept" stage of development.

The report to Congress on coal refining, which was called for in the FY 91 Appropriations Act, will form the basis for decisions on future budget needs for the program.

QUESTIONS FROM SENATOR FORD

Coal Refining

Question 9: Are you familiar with the coal refining process that uses hydrocracking techniques? What is DOE's current view of the viability of that process?

Answer: The term "coal refinery process" has been used to describe several very different process concepts for the conversion of coal to higher valued forms of energy. The Electric Power Research Institute has used this terminology to describe the coproduction of methanol and electric power from coal. Others have used the term to apply to the use of pyrolysis of coal to produce liquid and solid fuels. In its broadest sense, the term could be used to describe coal liquefaction and coal gasification technologies, but this would not be useful since these technologies already have a well-defined and understood meaning in the energy community. As used in the hydrocarbon process industry, the term "hydrocracking" has a quite specific meaning and relates to processes that use a catalyst and hydrogen under high pressure to convert heavier hydrocarbons to lighter, more-valuable materials. This type of processing is widely used in petroleum refining. The word "hydrocracking" could, of course, be used more generally to apply to any technique for converting hydrocarbon molecules in the presence of a hydrogen or reducing atmosphere (coal gasification, for example). However, as in the case of coal gasification, more precise and more descriptive terminology is generally used to specifically identify this group of conversion technologies.

In direct coal liquefaction, there are several catalytic staged liquefaction process concepts under development. Each of these uses catalytic hydrocracking techniques to produce lighter, more valuable hydrocarbons from coal. The hydrocracking technology used is similar, but not identical, to that used to process heavy oils in the petroleum industry. We believe that this approach, now being pursued in the DOE Direct Coal Liquefaction Program, is potentially a commercially feasible means for producing liquid transportation fuels and oil refinery feedstocks (which can be converted to petro-chemicals) from coal. We are aware of literature that describes a process called a "coal refinery" process which utilizes pyrolysis of coal in the presence of hydrogen to produce some liquid products and a coal char fuel. This approach is more precisely described as a hydropyrolysis rather than a hydrocracking technique, and is not at all similar to the hydrocracking technology utilized in the petroleum industry.

In summary, the viability of "hydrocracking" depends on the context in which the term is used and the specifics of the processes used.

QUESTIONS FROM SENATOR FORD

Coal-Derived Liquid and Gaseous Fuels

Question 10:	How is DOE's work in the area of coal liquefaction and coal gasification related to the work done by the Office of Conservation and Renewable Energy in alternative fuels?
Answer:	The alternate fuels work done by the Office of Conservation and Renewable Energy is focused on alcohol fuels (methanol and/or ethanol) produced from biomass as alternate transportation fuels. The work in coal liquefaction and gasification is focused on the production of a complete spectrum of hydrocarbon fuels (gasoline, jet fuel, diesel fuel, heating oils) and non-fuel products produced from coal. Alcohol fuels can also be produced from coal by gasification followed by conversion of the synthesis gas, and work in this area is also being pursued in the coal program.

QUESTIONS FROM SENATOR FORD

Coal-Derived Liquid and Gaseous Fuels

Question 11: Isn't there some potential for these technologies to produce coal-derived fuels capable of providing an alternative to conventional motor fuels?

Answer: A report issued last year by the National Research Council identified coal liquefaction as having significant potential for the production of transportation fuels from a large domestic resource. Current technology could produce these fuels at a cost competitive with crude oil priced in the range of $35-40 per barrel. Improvement potentials have been identified that could reduce costs to $30 per barrel crude oil equivalent by the late 1990's assuming an adequate research and development program. If these improvements are realized, coal liquefaction technology could be competitive soon after the year 2000 when world crude oil prices are projected to be at or above $30 per barrel.

Coal-Fired Locomotives

Question 12: What would be the effect of DOE discontinuing its funding of coal-fired locomotives?

Answer: I would make further commercialization of this technology the reponsibility of private industry.

QUESTIONS FROM SENATOR FORD

Coal-Fired Locomotives

Question 13: It seems that this program is close to commercialization and has potential for significant displacement of diesel fuel. Why would DOE choose to discontinue the program at this juncture?

Answer: If the coal-fueled diesel locomotive program is successful, commercialization is at least 5 to 10 years away. This is lower priority than some of the other coal programs. It has limited oil displacement capability (a maximum of 200,000 BBL/day of distillate fuel): It replaces a fuel not likely to be in short supply. (The production of gasoline requires the production of some heavier products). Good fiscal management requires choices to be made.

QUESTIONS FROM SENATOR FORD

Recommendations of the National Coal Council

Question 14: The National Coal Council has completed 10 reports since its inception. This includes 7 reports that have had recommendations on clean coal technologies.

Please provide for the committee a listing of the National Coal Council recommendations and the disposition of each by DOE.

Answer: The recommendations of the National Coal Council and the disposition of each by DOE are as follows:

REPORT	RECOMMENDATIONS
The Long-Range Role of Coal In The Future Energy Strategy of the U. S. (June 1990)	1 The Secretary of Energy should ensure that the NES acknowledges the importance of coal in the Nation's Energy and Economic Future.
	2 The Secretary of Energy Should Expedite the completion and deployment of selected Clean Coal Technology Projects, and in the future should direct the program toward new technologies which promise to yield higher efficiencies and lower environmental impacts.
	3 The Secretary of Energy should develop a program by which the economic risks associated with large-scale facilities based on coal can be mitigated so that commercial deployment of Clean Coal-based technologies can take place.
	4 The Secretary of Energy should ensure that the NES promotes the development and demonstration of technologies for producing coal-derived liquids and gases.
	5 The Secretary of Energy should ensure that the NES facilitates the efficient utilization of the existing coal transportation infrastructure and recommends federal eminent domain powers to secure adequate rights-of-way for the transport of coal over the time period examined in this report. Additionally, the strategy should support the implementation of the recommendations of the "Interstate Transmission of the Electricity" report of the NCC dated June 1986.

6 The Secretary of Energy should work with the Secretaries of the Interior and Labor, and the Administrator of the EPA to: Seek balanced, economic solutions to future mining-related environmental issues and more flexibility in bringing innovative solutions for mine safety to the work place; assure timely availability of federally-controlled coal reserves to private enterprise; and promote future mining technology development.

DISPOSITION 1a

The Long-Range Role of Coal In The Future Energy Strategy of the U.S. (June 1990)

1. The NES emphasizes the importance of coal.

2. DOE has followed both recommendations. We have:

   (1) Developed an expedited process for negotiating CCT demonstration projects. As a result, 33 of the 35 projects through Round 3 in the program have completed negotiations.

   (2) Focused CCT 4 on high efficiency, low polluting systems to a greater extent than previous rounds of the program.

3. Such incentives were proposed in the President's Clean Air bill. Similar incentives are encouraged in the NES.

4. The NES supports RD&D and use of all cost-effective alternative fuels and technology including use of coal derived liquids.

5. The NES promotes the efficient utilization of the coal transportation infrastructure and recommends federal eminent domain powers for rights-of-way. It also supports the timely enhancement of electric transmission capacity, where economic.

6. The NES states that DOE, DOI and EPA will work together on most of the recommended issues.

Industrial Use of Coal and
Clean Coal Technology
Addendum Report (June 1990)

Chapt. I-Industrial Boilers

1 Increase the emphasis on interagency review of the linkage between the national economy, national energy use, and the quality of life. The impact of the regulatory process with respect to cost-benefit, the impact on energy use, as well as the effect on health and welfare should be given particular attention. The results of these reviews should be widely communicated on an ongoing basis.

2 The energy content of various industrial products should be evaluated and published as a useful indicator of which industrial processes are more susceptible to energy impacts. Thus, as relative energy costs vary, the potential use of coal could be targeted in the most effective manner.

3 It is recommended that there be further research and development focused on processes that prepare, deep-clean, and size coal (ready-to-use fuel) for industrial use.

4 Emission standards should not require specific technology but should leave open the method of compliance.

5 Emission standards should not require a percentage reduction based on input but should be based on unit of output.

6 Establish aggressive technology transfer programs between industry and government.

7 Develop small coal firing systems for boilers with an input of less than 100M Btu per hour, applying some of the clean coal technologies.

8 The Secretary of Energy should encourage the coal industry to take the lead in promoting the increased use of coal in the Industrial Sector.

Chapt. II-Coke, Iron, and
Steel Industries

1 The Secretary of Energy should, through the Strategic Materials Committee, initiate procedures to designate coke and coal tar products strategic materials for the U.S.

DISPOSITION **2A**

Industrial Use of Coal and Clean Coal Technology Addendum Report (June 1990)

Chapter I

Industrial Boilers

1. The NES supports the assessment of the energy and economic impacts of Federal environmental regulation, and the streamlining of the regulatory process whenever feasible.

2. The energy efficiency of industrial processes is a matter of economics and technology, and such information is generally available from public and private sources.

3. The FY92 budget proposal includes work in this area in the coal preparation program.

4. This is the Administration's position.

5. The percentage reduction requirement of the Clean Air Act was eliminated when the Act was revised in 1990.

6. An aggressive outreach and education program is being conducted in the CCT program and is encouraged by the NES.

7. Such a program is being conducted in the advanced combustion and atmospheric fluidized bed combustion programs.

8. The Secretary of Energy has encouraged the industry to take the initiative on this matter.

Chapter II

Coke, Iron, and Steel Industries

I. The Department will look into this and report back on our findings.

	2	The DOE should encourage research projects leading to cost-effective control technologies for coke ovens and development of advanced ironmaking processes.
	3	It is considered of extreme importance to identify global impacts, both environmental and economic, of replacing U.S.-produced coke with imported sources. Such an undertaking, however, is beyond the scope of this report. Therefore, it is recommended that the Secretary of Energy initiate, through the DOC or other entity, a program which will identify such impacts.
Chapt. III-Aluminum and Other Metals	1	The Secretary of Energy should encourage the research and development of technologies which can economically convert coal to pure carbon, thus expanding the markets for coal in the primary metal industry. Such carbon also may be the ultimate clean coal (free of ash, sulfur, and nitrogen impurities) to produce electricity through more efficient heat engines.
Chapt. IV-Glass, Brick, Ceramic, and Gypsum Industries	1	The Secretary of Energy should encourage research and development to evaluate the best means of applying coal to glass manufacturing and what new technologies may be required. This research and development should be undertaken with the participation of the glass industry.
Chapt. V-Cement and Lime Industries	1	Industry should make use of available technologies to clean, dewater, dry, and prepare coal fines rejected by the coal preparation plants. This product could then be marketed to the cement industry.
	2	The Secretary of Energy should take appropriate action to expedite the resolution of regulating uncertainties and should continue active involvement in preventing future such uncertainties.
	3	The Secretary of Energy should encourage expanded research and development of slurry technologies.

DISPOSITION 3a

Coke, Iron, and Steel Industries (cont.)

2. The Clean Air Act authorizes DOE and EPA to conduct such a program. The need for conducting such a program is currently under review.

3. DOE will look into this issue and report back.

Chapter III

Aluminum and Other Metals

1. The Office of Fossil Energy initiated a major program in 1987 to develop technologies for producing a suite of value added products from coal through the application of mild gasification techniques. This cost shared program includes multiple efforts and approaches to address a variety of markets for these products. One of the contractor teams is pursuing the production of pure carbon for various applications. The R&D effort is now at the 100 lb/hr development stage and a competitive procurement for a scale-up to 1 ton/hr is now underway.

Glass, Brick, Ceramic, and Gypsum Industries

1. Such a program is underway in our advanced combustion technology program. A promising coal-based glass-making technology is under development.

Chapter V

Cement and Lime Industries

1. The Department agrees.

2. The NES fully addresses the issue of regulatory uncertainties.

3. DOE has in the past and is proposing in FY92, a R&D program on slurry technologies.

4 The Secretary of Energy should encourage the further development of clean coal technologies for direct heat application in the lime industry.

Chapt. VI-Pulp and Paper Industry

1 Pursue increased coal usage in areas where coal already enjoys a competitive advantage over oil and natural gas. Competitive pricing is the key to increased usage of coal. Coal is most likely to be competitive in mills located near major coal fields.

2 For areas and mills where coal is not presently used, determine the price structure for all fossil fuels and be prepared to move in with coal as soon as the price structure changes in its favor.

3 The quality of coal across the country is not constant. A higher quality coal could be defined as one with a lower content of ash, sulphur, and moisture, a higher ash fusion temperature, and a higher heating value. If a higher quality coal can be offered, a customer will be faced with fewer operating problems in firing equipment, furnace and boiler, and ash collection and disposal.

4 Pursue increased coal usage particularly in mills with a significant need for fossil fuels. This would include the larger mills and those which do not generate most of their energy from self-generated and residue fuels.

5 There is substantial diversity between states in environment permitting procedures and implementation of the various regulations; this is a major deterrent to coal use. Expediting the resolution of these regulatory uncertainties will go a long way in expanding the use of coal.

6 It is probable that any mill of significance will have an adequate rail siding suitable for adaption for rail car deliveries of coal. Any substantial quantities of coal that must be delivered over any great distance will require rail delivery. Efforts for coal use should be directed first at those mills with suitable rail access and facilities.

DISPOSITION 4a

Cement and Lime Industries (cont.)

4. The U.S. produces approximately 17 million tons of lime per year. About 80% of the lime produced in the U.S. uses coal as the primary energy source and over 90% of the plants use rotary kilns for the production of lime from limestone. Today the lime industry consumes about 5 million tons of coal per year. The emission of fine particulate is the primary environmental concern but this is being satisfactorily addressed with commercial technology. Most of the kilns can switch between oil, coal or gas and can be expected to switch dependent upon fuel prices and availability. Because of the availability of satisfactory commercial equipment, the DOE does not have an R&D program specifically targeted for lime production. The demand for lime is expected to grow with expanded utilization of scrubber technology resulting from implementation of the Clean Air Act.

Chapter VI

Pulp and Paper Industry

1. DOE agrees that this should be a focus of industry efforts.

2. DOE agrees that this should be a focus of industry efforts.

3. DOE agrees. Market factors will dictate what fuels will be used.

4. DOE agrees that industry should pursue these efforts.

5. The States have the authority to define the procedures they will utilize. DOE is working with State Legislative and regulatory bodies to encourage them to consider expanding the role of coal through a variety of mechanisms, including regulatory reform.

6. Industry is in the best position to undertake these efforts.

Chapt. VII-Food and Kindred Products	1	Dependable, quality coal burning equipment in smaller sizes typically found in food manufacturing plants must become available. These smaller units exist in Europe; however, they are not required to meet the 90% SO2 reduction requirements of the U.S.
	2	The Secretary of Energy should encourage a realistic and responsible national policy that balances the cost of environmental controls with the benefits to society.
Chapt. VIII-Durable Goods	1	The Secretary of Energy should encourage a high-level of research & development into small size combustor systems.
Chapt. IX-The Textile Industry	1	The Secretary of Energy should encourage a high-level of research and development activity into small size combustion systems.
Chapt. X-Refining and Chemical Industry	1	The DOE should continue to support and expand the development of technology for the conversion of coal into liquids and coal into gas.
	2	The DOE should continue to support and expand the research in chemicals derived from synthesis gas from coal.
	3	The Secretary of Energy should encourage Federal and State Governments to ensure that cogenerators have access to transmission lines and power mkts.
	4	The Secretary of Energy should encourage the redefining of a cogenerator as one who not only produces electricity, but produces useful coproducts, such as chemicals; uses energy as mechanical energy; or is an emissions reductions facility.
	5	The Secretary of Energy should encourage the expanded use of clean coal technology in industry through industrial liaison programs.

DISPOSITION 5a

Chapter VII

Food and Kindred Products

1. DOE has and continues to conduct R&D on coal-based systems for a variety of applications. The private sector should modify such technology to apply it to niche markets.

2. The NES is built on the necessity to develop national policies that balance environmental, economic, and energy objectives.

Chapter VIII

Durable Goods Industry

1. Such R&D has been conducted for several years.

Chapter IX

The Textile Industry

1. Such R&D has been conducted for several years.

Chapter X

Refining and Chemical Industries

1. The FY92 budget proposes to do so.

2. The FY 92 budget proposes to do so.

3. The National Energy Strategy calls for increased transmission access for wholesale electricity suppliers, including cogeneration.

4. The National Energy Strategy calls for reform of the Public Utility Holding Company Act. This would accomplish some of the goals called for here.

5. This is being done through the CCT outreach and education programs.

6 The Secretary of Energy should appoint an industry advisory committee, which should include members representing the chemical and petroleum refining industries, to advise on the research and development needs of the industry to provide for more coal use.

7 The DOE should continue its efforts to improve the image of coal in the eyes of the public.

DISPOSITION 6a

Refining and Chemical Industries (cont.)

6. This is being done in our coal R&D program on an informal basis through a "private sector dialogue" activity. However, a needs assessment will be prepared jointly with industry.

7. DOE is addressing coal's image through its outreach and education programs and has requested the National Coal Council to conduct a study on the subject.

REPORT		RECOMMENDATIONS
Clean Coal Technology (June 1986)		
Chapt. 2-Gov't. Policies and Clean Coal Use	1	The Secretary should use his office to aid in developing a consistent national energy policy which recognizes the role clean coal use must play in maintaining our future economic growth while ensuring a greater level of enrgy self-sufficiency and security. The Secretary must then insulate the programs used to develop clean coal technologies from arbitrary changes in directions and funding.
	2	Appropriately-sized demonstration plants are vital to successful implementation of clean coal technologies. The Federal government, along with state governments, needs to take an active role in sharing the financial and technical risks of bringing clean coal use technologies to commercial fruition. Financial grants by government on a cost sharing basis with industry are likely to produce the most successful and timely projects.
	3	With future strictures expected on DOE budgets because of the Gramm-Rudman legislation and other deficit reduction programs, innovative methods need to be found to pick up the shortfall in funding available for developing clean coal technologies. The Secretary should take the initiative in exploring the possibility of establishing development consortia which include DOE, the governments of the coal producing states, and major coal users and producers.
	4	The Secretary should work to convince public utility regulatory agencies that the cost of clean coal use technology research, development, and demonstration will ultimately benefit not only the nation but the utility customers as well. As such, the cost and risk of developing clean coal technologies is a cost of doing business and these costs must be recoverable from the rate payer.

DISPOSITION 7a

Clean Coal Technology (June 1986)

Chapter 2

Government Policies and Clean Coal Use

1. With the release of the NES the importance of coal's role in the Nation's energy future has been emphasized and clarified. However, insulation of programs from changes in direction and funding is neither possible nor desirable given that priorities change from year-to-year and budgets are defined not only by proposals submitted by DOE but by administration and Congressional inputs as well.

2. This is being fulfilled with implementation of the CCT demonstration program.

3. This is not an issue for the CCT Demonstration program; funds have been appropriated in advance.

4. Through the CCT outreach and education programs public utility regulatory agencies among others are being provided such information. Regulatory incentives were proposed by the President in his Clean Air Act for utilities who opted to use CCT's. Most of these were not adopted by Congress.

5 The Secretary should recommend to the Congress and EPA that emission standards should be revised so that they define only control levels which are linked to health and welfare requirements. The selection of the method of control used to meet these requirements should be left to the coal producer.

Coal Conversion (June 1986)

Federal Policies Affecting Technical Considerations

1 The Secretary should establish demonstration projects in identified technology areas with emphasis on establishing fuel switching capabilities (oil/gas/coal) as widely as possible.

2 The Secretary should establish a national clearinghouse for exchange and dissemination of technical information resulting from technology demonstration projects and from other industrial and electric utility coal conversion projects.

Federal Policies Affecting Environmental Considerations

1 The present exemption from Prevention of Significant Deterioration permitting and from New Source Performance Standards for coal converting facilties should be retained within the Clean Air Act and its regulatory framework. Specifically, the DOE definition of "coal capable" under the Powerplant and Industrial Fuel Use Act should be retained and adopted by EPA.

2 The Secretary, in conjunction with the Administrator of EPA, should form a DOE/EPA task force to find ways to streamline the federal/state/local permitting process attendant to coal conversion projects.

DISPOSITION 8a

Government Policies and Clean Coal Use (cont.)

5. DOE has been working with EPA to ensure that broad flexibility is provided for compliance with environmental regulations. The new Clean Air legislation provides such flexibility on many key points.

Coal Conversion (June 1986)

Federal Policies Affecting Technical Considerations

1. Several CCT demonstrations projects would facilitate fuel switching or the production of coal based liquids.

2. The aggressive CCT outreach and education program is providing the information needed by the private sector and regulators.

Federal Policies Affecting Environmental Considerations

1. The May 1987 amendment of the Powerplant and Industrial Fuel Use Act retained the Department of Energy's definition of "coal capable" with respect to existing powerplants which convert to coal. However, as a result of the 1987 amendment a new powerplant is considered "coal capable" if:

   - it has sufficient inherent design characteristics to permit the addition of equipment (including all necessary pollution devices) necessary to render such electric powerplant capable of using coal or another alternate fuel as its primary energy source; and

   - the plant is not physically, structurally, or technologically precluded from using coal or another alternate fuel as its primary energy source.

2. DOE and EPA are working very closely in the implementation of the Clean Air Act Amendments.

3 To demonstrate a coal converting facility's compliance with ambient air quality standards, where the EPA has good ambient air quality data are not available, th EPA should adopt more realistic modeling assumptions based upon actual operating conditions and experience, including stack height and plant operating rates.

4 The Delayed Compliance Order concept in the Clen Air Act which expired on December 31, 1985, should be extended and included in any revision of the Clean Air Act.

5 The Secretary should host a national conference of the governors of coal-producing and coal-utilizing states to encourage the states to adopt legislation which will provide incentives for and remove barriers to coal conversion.

6 The exemption from hazardous waste regulation in the Resource Conservation and Recovery Act for high volume utility wastes, including fly ash waste, bottom ash waste, slag waste, and the flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels, should be retained.

Federal Policies Affecting Economic and Financial Considerations

1 The two Federal Power Act provisions for financing and cost recovery, (a) "Construction Work in Progress" in the rate base and (b) Oil Conservation Adjustment, provide economic incentives for electric utility coal conversions and should be retained.

2 If federal tax simplification legislation is not enacted and the current tax approach is retained, the federal government should retain the following important provisions of the federal tax code which facilitate coal conversion: (a) the investment tax credit (10 percent on most new capital spending), (b) depreciation and amortization schedules (allowing tax write-off of capital equipment over a 15-year life and a write-off of pollution control equipment added to existing plants over a five-year period), and (c) the allowance for state and municipality issuance of tax-free bonds to finance pollution control equipment.

Federal Policies Affecting Environmental Considerations (cont.)

3. DOE agrees and has been working with EPA to adopt such assumptions.

4. Delayed Compliance Orders were authorized by 113(d) of the Clean Air Act, as amended through 1977. Because of the content of the recommendation, it is assumed that the Coal Council recommendation related to 113(d) (5), which authorized delayed compliance orders for stationary sources ordered to convert from oil or gas to coal, or which converted to coal in anticipation of curtailment of natural gas supplies. These fuel conversion delayed compliance orders expired at the end of 1985.

   The Clean Air Act was amended on November 15, 1990. Title VII of the amendments replaced all of existing Section 113 with new language. The new 113 provides for enforcement orders which allow continued violations for a period of up to one year, and includes no provision explicitly addressing fuel conversions. In short, the National Coal Council recommendation was not implemented.

5. DOE has been actively working with State governments to advise them on incentives which could be provided to encourage the use of coal and CCT's. The NES is committed to such actions.

6. This issue will be debated when the Resource Conservation and Recovery Act is reauthorized in Congress over the next two years.

Federal Policies Affecting Economic and Financial Considerations

1. The Department has taken no action to remove the provisions of the Federal Power Act which provide for financing and cost recovery through, (a) Construction Work in Progress, and (b) the Oil Conservation Adjustment. These provisions, as approved by the Federal Energy Regulatory Commission, are still available to electric utilities converting powerplants to coal.

2. The 1990 tax reform bill has overtaken response to these issues.

Transportation Sector	1 The Corporate Average Fuel Economy (CAFE) standards under the Energy Policy and Conservation Act which require a vehicle manufacturer to achieve a minimum average mile-per-gallon performance for all gasoline and diesel-fueled vehicles it produces should be altered. 2 The DOE should position itself to deal in a timely fashion with the question of whether coal-derived liquids (other than coal-derived gasoline or diesel fuel) and alternate fuel-burning vehicles meet the EPA emission standards. 3 The federal government can provide increased market support for coal-derived fuels (other than coal-derived gasoline or diesel fuel) by expanding its coal-derived liquid fuel program for government vehicle fleets.
Commercial/Residential Sector	1 The NCC encourages the Secretary to retain and expand programs which move toward development of the clean coal technology necessary for coal to penetrate this market.

DISPOSITION **10a**

Transportation Sector

1. The NES calls for a study by the National Academy of Sciences on the CAFE standards.

2. As a part of DOE's coal liquefaction program, vehicle testing, including emissions testing, is being conducted.

3. This issue is under consideration as a result of the NES proposal to require automotive fleets to use alternative fuels.

Commercial/Residential Sector

1. The Department has over the last several years conducted R&D on coal based systems for the commercial and residential sectors.

REPORT	RECOMMENDATIONS
Reserve Data Base (June 1987) Chapt. 1-Analysis of in Deficiencies Existing Data Base	1 In order to be more consistent, the NCC recommends that a policy be instituted to ensure that more quantitative standards for categorizing reserves be developed, adopted and implemented which will recognize and realistic reserve estimation criteria, mineability and recovery criteria, as well as the impacts of competing land uses.
	2 The NCC further commends tnat this effort centrally coordinated and concurrently adopted by all parties developing and implementing this policy so that a single reliable date base emerges, as is commonly found among other coal producing nations.
	3 Efforts to develop a reliable data base which recognizes coal quality, recovery differences, preparation yield losses, and so forth must be undertaken. Efforts such as the U.S. Geological Survey's National Coal Resource Data System should be encouraged.
	4 Clarification of the "resource" versus reserves" issue must be made, and reserves must be identified in such a manner as to clearly convey that they are that part of the National Treasury that can be mined and utilized by society. It is suggested that the Demonstrated Reserve Base be redesignated the "Demonstrated Resource Base" and that a new category termed "Recoverable Reserve Base be established as well.

DISPOSITION 11a

RESERVE DATA BASE (June 1987)

Chapter 1

Analysis of Deficiencies in Existing Data Base

In 1987 and 1988, EIA conducted a thorough review and evaluation of all available sources of coal quality data to determine if better data are available to improve the DRB. This information was used in a series of statistical analyses to evaluate current and alternative methodologies for developing the DRB. This study, Development of a Revised Methodology to Estimate the Distribution of the Demonstrated Reserve Base (DRB) by Quality, August 1988, established minimum data requirements for reliable projections of coal quality data for unmined coal reserves, and described the best available methodologies using current data. Further, the report listed recommendations for additional or alternative sources of coal quality data and emphasized the importance of a complete update of the coal resource data base.

In order to inform the current and potential users of EIA resource and reserve data of the contents and scope of the currently available data base, EIA published Estimation of U.S. Coal Reserves by Coal Type: Btu and Sulfur Content, September 1988. This report clearly delineates EIA's current level of knowledge on the characteristics of the coal in the DRB, summarized by State, and presents estimates on how much will be recoverable. The report describes the methodology and the adjustment factors used to estimate coal quality and coal availability and recovery rates. This report was distributed to State and Federal agencies, coal industry principals, and academics and consultants, in order to inform them, and also to stimulate comments and suggestions as to additional sources to data that might be used to improve the current data base.

With both the USGS work on its Coal Availability Studies and the results of its own earlier efforts in mind, the EIA initiated a new program to expedite the use of the best available source data on coal resource tonnage, coal quality, and reserve-related minability and recovery data. This new Coal Reserves Data Base (CRDB) Program involves the State geological surveys, in consultation with USGS and other Government and private expertise. The CRDB program established a set of criteria designed to ensure an updated, centrally coordinated data base, using an independent Steering Committee of coal resource experts and a set of procedural guidelines that permit the flexibility needed to accommodate localized mining and geology factors.

The CRDB Program began with an EIA-sponsored conference in February 1990. At that conference, representatives of major Federal and State coal resource agencies and leading coal industry and research analysts defined the critical coal reserve data needs and methods for implementing the CRDB program. Subsequently, 21 State agencies submitted comprehensive plans to update their reserve data. EIA prioritized these State plans based on the relative competitive value of the coal, data availability and the level of State production and reserves. Of these, 16 were selected for near-term support.

In September 1990, cooperative agreements were negotiated with the Ohio Geologic Survey and the Wyoming State Geological Survey to update their reserve data. These two projects are scheduled to be completed in September 1991. Further cooperative agreements with other States await funding as it is determined how they fit into the long-range plans of the Department.

Chapt. 2-Laws and Regulations Affecting the Availability of Coal Reserves	1	The Secretary should undertake a major examination of all current local, state, and federal laws and policies, regulations, and decisions of regulatory bodies to determine which of these adversely impact the amount of mineable coal reserves in the U.S.
	2	The Secretary should establish a high level inter-agency working group within the Federal Government to study, address and analyze any and all proposed laws, policies, regulations, statutes and actions of regulatory bodies which pertain to the mining of and exploration for coal. Such a working group might include the Secretaries of DOE, DOI, DOT, DOL, as well as Administrators of EPA, FERC, and other appropriate officials.
	3	The Secretary should consider a major high-level meeting of governors and key legislators from coal-producing states to identify the laws, policies, regulatons and decisions that could significantly reduce the amount of recoverable coal.

DISPOSITION 12a

Chapter 2

Laws and Regulations Affecting the Availability of Coal Reserves

1. As EIA stated in its testimony to Congress in September 1987, EIA, DOE and other coal analysts only use the DRB as the starting point for their analyses of proposed laws, regulations, policies, statutes and actions which pertain to coal mining. The DRB is reduced before it is used to try to account for legal, technical, and environmental constraints (leaving recoverable reserves). It is after all of these are taken into account that any evaluation of a proposed law is begun. It should also be noted that the CRDB Program, discussed above, will have each State agency try to take these kind of constraints into account before they deliver their updated reserve date.

2. The NES calls for the establishment of an interagency group to develop guidelines for preparing energy impact analyses. these impact analyses would be considered into all major rulemakings and legislative actions to assess the effects on domestic energy supplies.

3. The NES held 18 high level public hearings to address all important issues relating to energy. These hearing s included testimony from leaders in industry, government, and the public. Included in these hearings were extensive testimony and reports on all issues of importance to the coal industry, including resource issues.

Chapt. 3-The Effect of Regulations on the Coal Reserve Base

1 The Secretary should institute a comprehensive, highly detailed survey of U.S. coal producers in order to obtain a more in-depth and complete view of the quantifiable impacts that laws, policies, regulations, and decisions of regulatory bodies have on the recoverable coal in the DRB.

2 The Secretary should initiate a study addressing the long- and short-term impacts to recoverable coal in the DRB due to increased costs needed to comply with laws, policies, regulations, and so forth. This study would help to clarify whether some or all reserves thus affected and removed from potential production in the short-term should still be considered recoverable reserves in the future.

3 The Secretary should develop a framework which will readly allow quantification of the impacts to the recoverable coal in the DRB stemming from changes in or from newly proposed laws, policies, regulations, and decisions of regulatory bodies.

4 In order to facilitate the implementation of recommendation Number 3 (above), the Secretary should develop and propose legislation that would impoe an "Energy Impact Statement" (similar to the Environmental Impact Statement). Such a procedure would force legislative, administrative, and regulatory bodies to consider the impact of new or proposed laws, policies, and regulations on current and future energy supply and security as well as the economic impact that such laws, policies and regulations may have.

DISPOSITION 13a

Chapter 3

The Effect of Regulations on the Coal Reserve Base

The CRDB Program is designed to have experts in the State geologic agencies quantify the DRB and the amount of the DRB which is recoverable. Although a survey of coal producers could be undertaken, it would place an unusually high burden on the industry and require them to divulge proprietary information. The CRDB program has been fostering cooperation between the private producers and the State geological agencies in a way which will not compromise their sensitive data. As stated above, we currently determine the impact on the DRB and recoverable reserves of proposed changes to existing laws before any analyses are conducted. After the CRDB has been completed we should be able to develop a more accurate understanding of the impact of future proposed changes in laws on the DRB and recoverable reserves.

The NES calls for the establishment of an interagency group to develop guidelines for preparing energy impact analyses. (See response to Chapter 2, no. 2, above). These guidelines should incorporate issues such as those listed in recommendations nos. 1 - 4 in Chapter 3.

REPORT	RECOMMENDATIONS
Innovative Clean Coal Technology Deployment (November 1988)	1 Complete the ongoing DOE-Cosponsored ICCT Demonstration Initiative as planned.
	2 Clearly define the scope and extent of ICCT "Deployment."
	3 Actively encourage, at the state level, utility and industrial participation in ICCT deployment efforts by allowing or providing: (see page 5 of report)
	4 Ensure that air quality legislation places priority on sustaining the remarkable national progress made over the past 15 years in emission reduction with the least impact on cost and productivity by providing: (see page 6 of report)
	5 Lower Federal and state environmental regulatory barriers to wider use of ICCT options by providing: (see page 6 of report)
	6 Modify Federal, state and local environmental permitting procedures to expedite and encourage ICCT deployment, and provide a permitting reference for consistent and uniform application of Federal regulations.
	7 Conduct an ICCT public education and consensus-building campaign.
	8 Provide, where appropriate, Federal and state economic incentives to accelerate ICCT deployment without distorting the energy mkt.
	9 Remove restrictions on collaborative technology development and demonstration investments by commercial competitors.
	10 Establish a bipartisan coal and related technology export policy coordinating council under the auspices of Congress and the President.

DISPOSITION 14a

Innovative Clean Coal Technology Deployment (November 1988)

1. The CCT program is expected to be completed.

2. This was done as a part of the President's Clean Air proposal. Deployment incentives were proposed and limitations on their use were defined.

3. Much of what the NCC proposed was included as incentives in the President's Clean Air proposal.

4. Most of what the NCC recommended was included in the recently enacted Clean Air legislation.

5. Most of what the NCC recommended was included in the recently enacted Clean Air legislation.

6. Some of the recommendations were included in the recently enacted Clean Air legislation.

7. This is being done as part of DOE's CCT outreach and education programs.

8. Such incentives were proposed as part of the President's Clean Air legislation and are called for in the NES.

9. DOE supports removal of restrictions on collaborative technology development and demonstration investments by commercial competitors and has cooperated with the Department of Commerce to accomplish this objective.

10. DOE supports such a council assuming it is broadened to the full slate of energy resources and technology.

11 Review and modify applicable Federal law, as appropriate, to permit the U.S. coal industry to form trading companies for the export of coal and coal technologies.

Innovative Clean Coal Technology Deployment (November 1988) (cont.)

11. This is proposed in the NES.

REPORT	RECOMMENDATIONS
Improving International Competiveness of U.S. Coal and Coal Technologies (June 1987)	1 Coal should be accorded a higher priority in U.S. trade policy in order to expand its contribution to the U.S. balance of trade.
	2 Industry and government should work together in the pursuit of new market opportunities and development of aggressive trade negotiation strategies.
	3 United States trade policy should recognize that a reduction in coal trade barriers in major coal importing countries could result in expanded U.S. coal exports as the U.S. captures a share of resulting increased import demand.
	4 The U.S. should consider the impact of exchange rate fluctuations between both major trading partners and competing exporters, (Australia, South Africa and Canada), as these rates have an important bearing on U.S. competitiveness in world coal markets.
	5 The U.S. government can affect U.S. coal competitiveness by addressing the cost of producing coal. It is of critical importance that the tax and regulatory burden on the U.S. coal industry be held to the minimum, consistent with sound resource and environmental management and equitable tax policies.
	6 The Federal government and the coal industry should pursue a broad, integrated and coordinated strategy to promote the use of coal in developing countries for power generation in the interest of national security and expanded coal exports.
	7 Further funding by the U.S. government and private industry of research and development efforts for clean coal technologies will contribute to increased competitiveness of U.S. coal exports.

DISPOSITION 16a

Improving International Competiveness of U.S. Coal and Coal Technologies (June 1987)

1. DOE is cooperating with other government agencies to accord higher priority to coal in U.S. trade policy. Deployment of clean coal technologies as a precursor to increased coal utilization is also being promoted where possible.

2. DOE is working with industry in the pursuit of new coal market opportunities and development of aggressive trade negotiation strategies. Activities include: public conferences and seminars; participation in international trade exhibitions; sponsorship of clean coal technology trade missions; publication of coal and technology industry directories; and special market studies, i.e., "Innovative/Alternative Transport Modes for Movement of U.S. Coal Exports to the Asian Pacific Basin."

3. DOE is working to reduce coal trade barriers in major coal importing countries through several multi-lateral organizations, the International Energy Agency, CATT, and the U.N Economic Commission for Europe.

4. Consideration of the impact of exchange rate fluctuations and policy to affect rates falls outside the primary responsibility of DOE, however, DOE continues to stress this issue in interagency activities and programs.

5. U.S. Government responsibilities for taxes and regulations on the coal producing industry fall outside DOE. DOE does support the position that taxes and regulation be held to the minimum consistent with sound resource and environmental management and equitable tax policies.

6. DOE has made a concerted effort to cooperate with the coal industry in the pursuit of a broad, integrated and coordinated strategy to promote the use of coal in developing countries. The major elements of DOE's Coal and Technology Export Program have been developed in cooperation with industry and have included joint participation with industry.

7. Significant funding for the research, development and demonstration of CCT's continues. $430 million has been proposed for the program in FY92. DOE continues to support funding of R&D for clean coal technologies to increase competitiveness of U.S. Coal Exports

8 The U.S. government should assess the extent to which transportation policies of competin coal export countries impact U.S. exporters.

9 The Federal government should continue to pursue policies which foster competitive systems for the inland movement of export coal from mine to port and avoid policies which increase freight or port costs.

10 Private enterprise and the Federal governmen need to develop more sophisticated and bette integrated international financing methods to raise the capital required for the scale of investments associated with new coal-fir powerplants in coal importing countries.

DISPOSITION 17a

Improving International Competitiveness of U.S. Coal and Coal Technologies (June 1987) (cont.)

8. DOE has considered transportation policies of competing coal exporting countries and means to increase the competitiveness of U.S. coal exports in the study "Innovative/Alternative Transport Modes for Movement of U.S. Coal Exports to the Asian Pacific Basin."

9. DOE supports policies to foster competitive systems for inland movement of export coal from mine to port and the avoidance of policies which increase freight or port costs. The responsibilities for implementation of these policies, however, rest with other Federal agencies outside DOE.

10. DOE supports and promotes cooperation among private enterprise, the Federal Government and international lending institutions to develop and integrate international financing methods to raise the capital required for new coal fired powerplants in coal importing countries.

REPORT		RECOMMENDATIONS
The Use of Coal In The Industrial, Commercial, Residential, and Transportation Sectors (December 1988)	1	The transportation sector consumes 27 percent of the total U.S. energy input and nearly two-thirds of the oil used in the country. It is also the only sector of the economy almost entirely dependent upon liquids with little fuel flexibility or diversification. The Secretary should commission a study of the methods of producing alternative transportation fuels from coal.
	2	Continue to support programs promoting research and development to convert syngas to liquid, coal to gas, and coal to liquid in order to lessen U.S. dependence on imported oil. Demonstration programs are needed for several reasons.
	3	The image of coal must be rebuild based upon its presently known environmental benefits resulting from clean coal technologies. To this end, DOE should convene a work group appropriate executive branch agencies/departments; state and local government representatives (National Governors Association, National Conference of State Legislators, National League of Cities); and industry officials to develop a substantial public outreach program to improve perceptions and attitudes related to coal.
	4	Encourage Federal agencies such as the GSA, the Veterans' Administration, the Postal Service, the DOO, as well as the DOE to increase the use of coal in public facilities.
	5	Undertake a review of the permitting process and the regulations which affect use with appropriate federal and state agencies with the objective of reducing inconsistencies and overlaps.

DISPOSITION 18a

The Use of Coal in the Industrial, Commercial, Residential, and Transportation Sectors (December 1988)

1. Numerous studies have been conducted on the technology and cost of producing liquid transportation fuels from coal. The NES calls for aggressive Federal, State and private efforts to increase the use of alternative fuels in transportation, and for continued R&D in coal derived fuels.

2. R&D on synthetic fuels from coal continues. The FY92 budget includes funding for such programs. Several synthetic fuels projects are being demonstrated under the CCT demonstration program.

3. This is being done. DOE's CCT Outreach program and DOE's Coal Awareness Steering Committee directly respond to the recommendation.

4. This was discussed as a part of the NES development process. Whether coal can be the fuel of choice in Federal facilities depends on a number of factors including technical and economic feasibility.

5. The Vice President's Council on competitiveness reviews regulatory policy on an on-going basis. The NES examines at great depth the impact of regulatory policy on energy production and use and recommended a comprehensive package of reforms.

6 Investigate the use of economic incentives that would have the largest impact on increasing the use of coal in the industrial, commercial, residential, and transportation sectors and sponsor legislation as deemed appropriate.

7 Stimulate interest within the commercial sector to develop new coal-fueled district heating and cooling systems.

8 Review and evaluate in greater detail the programs of foreign countries which have successfully implemented coal use in the industrial, commercial, residential, and transportation sectors.

DISPOSITION 19a

The Use of Coal in the Industrial, Commercial, Residential, and Transportation Sectors (December 1988) (cont.)

6. Consideration was given to such incentives in the NES process. It was determined however, that their cost was likely to outweigh their benefits.

7. DOE's Fossil Energy and Conservation Offices are jointly working on studies and technologies to address these market needs.

8. This is an ongoing activity which, in part, drives the R&D being conducted by DOE.

REPORT	RECOMMENDATIONS
Interstate Transmission of Electricity (June 1986)	1 The Secretary should declare that it is in the national interest to have in place--and to reinforce as the need arises--strong interstate electric transmission networks, so as to maintain and enhance "coal-by-wire" power transfers among electric utilities and to achieve many other benefits in economy and reliability of electric power supply. 2 The Secretary or his representative should intervene or otherwise appear before state and local regulatory bodies that are considering the construction or siting of transmission lines that have interstate or regional implications. Such interventions or appearances should emphasize the transcendant national interest in the expeditious construction of such lines. 3 The Secretary or his representative should intervene or otherwise appear before state public utility commissions, when appropriate, to emphasize the need to permit electric utilities fully to recover the cost of constructing interstate transmission lines. 4 The DOE should encourage and support the FERC in its efforts to resist state encroachment upon its jursidiction over the interstate transmission of electric energy. It is essential to the further development of the interstate and regional power grids that the pricing of interstate power flows remains the exclusive prerogative of the FERC.

DISPOSITION 20a

Interstate Transmission of Electricity (June 1986)

1. The National Energy Strategy calls for increased transmission access.
2. DOE supports recommendation. The DOE also completed a comprehensive assessment of transmission issues as part of the NES, and will release this report in a few weeks as a technical annex to the NES.
3. DOE supports this recommendation.
4. FERC's jurisdiction over interstate transmission transactions.

REPORT	RECOMMENDATIONS
Report on Industrial Boiler New Source Performance Standards (June 1986)	1 The Secretary should support the existing flat 1.2 LB SO2/MM BTU maximkum emission regulation for new industrial boilers with a heat input of 250 MM BTU/HR or greater. 2 The Secretary should not support the draft EPA regulations for industrial boilers greater than 100 MM BTU/HR, which includes a mandatory 90% SO2 reduction. 3 The Secretary should support a reasonable SO2 emission standard for new boilers above 100 MM BTU/HR heat input. Between 100-250 BTU/HR, the limitation should be established at the point which minimizes both delivered coal costs for the small industrial boiler and overall SO2 emissions. The level should be no lower than 1.2 LB SO2/MM BTU; 1.6 LB is used for illustration purposes in the report. The exact limitation should be based on study of geographic availability of coals with various sulfur contents and associated impacts on delivered coal costs and overall emissions. 4 The Secretary should ensure that NSPS regulations for new technologies be based upon careful studies of actual commercial units in the applicable size ranges. This is consistent with recommendations made by the NCC Report on Clean Coal Technology.

DISPOSITION 21a

Report on Industrial Boiler New Source Performance Standards (June 1986)

The recommendations in this report have been overtaken by events. Industrial New Sources Performance Standards were promulgated by EPA several years ago. DOE defended the NCC position.

QUESTIONS FROM SENATOR MALCOLM WALLOP

Coal Refining

Question 1: Currently the emphasis of DOE's coal refining activities is on added value to liquid, gaseous and solid energy products. This is what is occurring at the ENCOAL project near Gillette, Wyoming, which produces low-sulfur fuel oil and a clean solid fuel.

a. However, coal also can be refined into non-energy products. Would you agree that coal offers a significant potential feedstock for non-energy products such as carbon-based chemical intermediates, coke and ceramics?

b. The FY 91 Interior Appropriations Act calls for a July 1, 1991, report to the Congress on coal refining. Would you agree to expand that report to fully examine the potential of coal refining to produce non-fuel products?

Answer:

a. Yes, coal can offer a significant potential as a feedstock to produce coke and carbon-based chemical intermediates. This is a primary focus of our R&D program in mild gasification. It should be noted that intermediate chemical markets may be limited in size.

b. As presently envisioned, the outline for the report to Congress on "coal refining technology" includes a number of proposed concepts, including some which produce non-fuel products. An assessment of the relative merits of these concepts will be accomplished, and the concepts that provide the most promising overall potential for commercialization will be more fully expanded in the report.

QUESTIONS SUBMITTED BY SENATOR MALCOLM WALLOP

Clean Coal Technology

Question 2:	During Congressional consideration of the 1990 Clean Air Act Amendments some of the electric utilities who were participating in the clean coal program indicated that they might drop out of the program should the Clean Air Amendments be enacted into law. What happened in this regard?
Answer:	Thus far, we have seen no indication that any participating utilities intend to withdraw and based on current indications, we expect a strong positive response from utilities to the Round 4 Solicitation.

QUESTIONS SUBMITTED BY SENATOR MALCOLM WALLOP

Clean Coal Technology

Question 3: Last year, Admiral Watkins streamlined the procedures for the negotiation of cooperative agreements under the clean coal program.

a. Did these new procedures result in expedited negotiations?

b. Did you meet the target set by Admiral Watkins to complete Round III negotiations by December 1990?

Answer: The new procedures have resulted in expedited negotiation procedures. In the 1990 Calendar Year, the Clean Coal Technology Executive Board designated by Admiral Watkins reviewed and recommended that the Admiral send forward 20 projects to Congress totalling $1.9 billion with a DOE cost share of $709 million (37.3%). The target set by Admiral Watkins to complete negotiations on all projects by December 1990 was met for 20 projects. At this time all negotiations on Rounds I&II have been completed and 2 projects from CCT-III remain in negotiation. The 2 projects from CCT-III were granted extensions by the Department at the request of the project sponsors.

QUESTIONS FROM SENATOR WALLOP

Clean Coal Technology

Question 4A: Would you explain to the Committee the impact that the WEPCo decision has had on the conduct of clean coal projects?

Answer: For some clean coal technologies (CCTs), the impact has been quite extensive, while for some others it has been manageable.

For local technical reasons, some CCTs have had only minor problems with the WEPCo decision. Some other temporary clean coal technologies have decided that the risks inherent in "research related no action assurances" issued by the EPA are manageable. These "assurances" in essence say that while the recipient may be violating the law, EPA agrees not to prosecute. Other groups could still sue the recipient of the "assurance."

Other CCTs have had greater difficulties. For example, one early CCT that dropped out of the program cited WEPCo as a major difficulty; the utility hosting the demonstration worried that if the demonstration failed, EPA's new PSD policy, e.g., the WEPCo ruling, would require significant costly upgrades before allowing the plant to return to its predemonstration condition. Another CCT project was delayed until EPA indicated that their project could go forward without PSD difficulties; the delay was substantial and increased project costs. Some clean coal technologies today are in need of permits, but may face delays in obtaining them because states need guidance from EPA on how Section 415 of the recent Clean Air Act amendments will be implemented.

QUESTIONS FROM SENATOR WALLOP

Clean Coal Technology

Question 4C:	What effect is this uncertainty (regarding the WEPCo decision) having on the Clean Coal Technology Program?
Answer:	Section 415 of the recent Clean Air Act contains language designed to allow temporary retrofit and permanent repowering Clean Coal Technology demonstrations to proceed without going through new source review procedures. The Administration is in the process of developing an interpretive rule and a notice and comment rule on various WEPCo issues, including implementation of Section 415. Until these rules are issued, states may not know how to permit such clean coal technologies with regard to NSR requirements.

Clean Coal Technology

Question 4D:	"How does the Administration intend to resolve this uncertainty?"
Answer:	The Administration has testified that EPA will propose a notice and comment rule possibly accompanied by an interpretive rule, by June 1 clarifying under what circumstances physical or operational changes at electric utility steam generating units will be subject to new source requirements. These rules also will implement the new requirements of section 415(b) of the Clean Air Act that provide WEPCo exemptions for temporary projects and permanent repowering projects.

QUESTIONS FROM SENATOR BURNS

Coal Refining

Question 1: Question: What is DOE's current view of the viability of coal refining techniques which employ traditional hydrocracking processes as opposed to liquefaction, gasification, or mild gasification?

Answer: At the request of Congress, the Department has initiated a study on the "Coal Refinery concept." Included in this study will be a listing and description of the various processing concepts that might be included under this terminology. Direct coal liquefaction technology is the only technology that we know of that utilizes hydrocracking technology similar, but not identical, to traditional hydrocracking technology as used in petroleum refining. Many of the "Coal Refinery" process concepts that we are familiar with employ some type of pyrolysis processing. These do not use catalysts and are not closely related to petroleum hydrocracking technology. The pyrolysis liquids may be upgraded utilizing combinations of coal chemical and conventional petroleum processing techniques.

The viability of "hydrocracking," in its broadest definition, will depend on the context in which the term is used and the process specifics.

QUESTIONS FROM SENATOR BURNS

Coal Refining

Question 2:	What programs in DOE at the present time focus on coal refining using techniques similar to petroleum refining that apply to both high-and low-sulfur coals?
Answer:	As described in Question #1, direct coal liquefaction utilizes catalytic hydrocracking techniques similar, but not identical, to those used in petroleum refining. Direct liquefaction will process both high- and low-sulfur coals of different ranks. The liquefaction product can be a feedstock to oil refineries to produce a slate of fuels and petrochemicals.

QUESTIONS FROM SENATOR BURNS

Coal Refining

Question 3:	How many awarded clean coal technology programs involve coal refining of both high-sulfur and low-sulfur coals as well as lignites?
Answer:	Two projects were awarded contracts under the Clean Coal Demonstration Program: (1) the ENCOAL mild gasification project to produce a dewatered compliance solid boiler fuel and a compliance liquid boiler fuel similar to a Number 6 fuel oil; and (2) the Ohio Fuels project which proposes to process a mixture of coal and petroleum resid to produce a syncrude which may be upgraded to produce specification heating and transportation fuels. In addition, Air Products and Chemicals, Inc., was selected for negotiation under the Clean Coal III solicitation. The proposed project will demonstrate the coproduction of methanol and electricity employing liquid-phase methanol technology.

QUESTIONS FROM SENATOR BURNS

Coal Refining

Question 4: Where are the small-scale development units which demonstrate the reduced cost of producing liquid fuels from coal? What technologies do they employ? What is the cost?

Answer: The small-scale development units utilized in the Direct Liquefaction and Surface Coal Gasification Programs include the Wilsonville two-stage direct liquefaction proof-of-concept unit, the LaPorte once-through methanol alternate fuel proof-of-concept, the HRI bench-scale staged direct liquefaction bench-scale unit, and the 100 pound/hour process research units in the Coproducts (mild gasification) Program. The objective of the Direct and Indirect Liquefaction Program is to produce transportation liquids which will compete with petroleum crude at $30/bbl. The objective of the Mild Gasification Program is to produce a suite of value-added solid, liquid, and gaseous products which will provide economic incentive to use coal in producing environmentally superior premium products such as formcoke and chemical intermediates.

QUESTIONS FROM SENATOR BURNS

Coal Cleaning

Question 5: Why does DOE seem to emphasize post-combustion cleanup rather than cleaning the fuel? Wouldn't that be both more economical and more efficient?

Answer: In recent years, the Department has pursued a balanced approach for using coal cleanly. This approach involved research activities for cleaning coal prior to combustion and post-combustion flue gas cleanup. Both of these activities were carried out to develop technologies that would be available to industry in complying with Acid Rain legislation (part of the Clean Air Act Amendments of 1990) for existing facilities in the most cost effective way for each specific application.

For post-2000 facilities, the Acid Rain legislation imposes a cap on CO2 emissions. For these future facilities, DOE is emphasizing the development of advanced technologies such as Pressurized Fluidized Bed Combustion and Integrated Gasification Combined Cycles as the most efficient means for controlling pollutants.

Funding of $4,530,000 is proposed in FY92 for coal preparation.

QUESTIONS FROM SENATOR BURNS

Coal Refining

Question 6: What is DOE's interpretation of "achieving greater efficiency"? Does this only apply to electric power generation or does it apply to producing coal-derived refined fuels?

Answer: "Achieving greater efficiency" is a term normally applied to coal-fired power generation; however, it also applies to producing coal-derived fuels. Current R&D is directed to increasing the yield and reducing the cost of coal-derived fuels through achieving greater efficiency in the conversion processes.

QUESTIONS FROM SENATOR BURNS

Coal Refining

Question 7: What is the difference between "the mild gasification program" at METC and the "coal refinery" project being constructed by ENCOAL? In the DOE Fossil Energy Review of July-September 1990, this project was referred to as "mild gasification." Why is it now called a "refinery"? What is the difference? Will the "refined" products be the same from a high-sulfur coal as from a low-sulfur coal? What non-fuel products are produced? What are the gases and what are their markets? Can the liquids produced by the ENCOAL plant be used as transportation fuels?

Answer: The objective of the mild gasification research and development program at METC is to develop a process to produce a suite of value-added products from coal such as formcoke, electrode binders, carbon black, and activated carbon. The objective of the ENCOAL project is to utilize mild gasification to produce compliance solid boiler fuel and compliance liquid fuel equivalent to a Number 6 fuel oil. In a broad sense, the coal refinery concept definition includes process concepts which produce multiple products from coal and could include electricity generation. Therefore, mild gasification is a type of coal refinery concept. The refinery products produced will vary depending on the process concept conditions and coal type utilized; therefore, the products from high-sulfur coal will likely be different than from low-sulfur coal. As indicated above, nonfuel products such as metallurgical coke and chemicals are included in the product mix. The markets for the gases are varied depending on the concept utilized in the coal refinery. In the case of ENCOAL, the gases are consumed internally for process heat. It is our understanding that the ENCOAL liquids cannot be utilized for transportation use without upgrading. The feasibility and economics of this upgrading have not been established.

QUESTIONS FROM SENATOR BURNS

Coal Refining

Question 8: **What coal refinery concepts are discussed in the report you mentioned in your testimony which is being prepared for Congress? Do they include hydrocracking? Are they similar to the well-known petroleum refining processes? Has DOE investigated the Union Carbide hydrocarbonization process and the Carbon Fuels Corporation Charfuel process?**

Answer: Approximately 30 potential systems involving liquefaction, gasification, mild gasification, and biological concepts will be considered. The report will provide details and short descriptions on each of these systems and will go into greater detail including information on technical, environmental, and economic (where available) aspects for about eight to ten concepts which have stronger potential for eventual commercialization. As we understand it, the direct hydrocracking of coal is not analogous to technology utilized for petroleum hydrocracking except it is similar in the case of direct coal liquefaction. The DOE is aware of the Union Carbide hydrocarbonization process and the Carbon Fuels Charfuel process.

DOE had a major demonstration project in the 1970's which was based on the Union Carbide hydrocarbonization process. The Coal-Con Clean Boiler Fuel demonstration project experienced technical and corporate organizational difficulties and did not proceed beyond the phase I experimental feasibility and commercial design activity. DOE is currently cosponsoring bench-scale studies of the Carbon Fuels Corporation Charfuels concept at WRI.

QUESTIONS FROM SENATOR BURNS

Coal Research and Development

Question 9: What is meant by the paragraph commencing "Given this..."? Do you mean that more funds should be allocated to programs relating to the use of coal as an energy supply option? Do you believe funding other coal-related programs would reduce the funds allocated to coal-as-fuel programs?

Answer: The subject paragraph questions the need to treat nonfuel uses of coal any differently than other categories such as coal-fired, high efficiency power systems, emission control systems for coal, or fuels from coal. Nonfuel uses of coal are part of the existing coal R&D program as are other coal uses. The merits of any technology in any category must be judged on the basis of its technical/economic viability, market potential, and contribution to the national effort. Every year there are more good ideas than available funding. Technologies or projects must be prioritized and choices made. Wherever possible, competitive evaluations and choices are made by means of the Federal Government's competitive procurement process. Unsolicited proposals are subjected to peer reviews. This kind of critical screening helps assure that the most promising technologies are selected for development. Selectively mandating a few specific coal programs with separately mandated reporting requirements is not conducive to a coherent, prioritized coal research program.

QUESTIONS FROM SENATOR BURNS

Clean Coal Technology - Advanced Hardware

Question 10: You speak of "advanced hardware" as being important in increasing coal exports. What about exporting clean fuels that can be used in existing facilities for either coal-fired or oil-fired facilities?

Answer: Clean fuels are becoming more important in increasing coal exports. DOE's Clean Coal Technology R&D and demonstration programs are sponsoring technologies that upgrade coal through removing impurities and lowering ash and moisture content. These technologies generate solid as well as liquid form products that can be used on existing coal and oil-fired facilities.

Coal Refining

Question 11: Has DOE done any work on diesel engines fired with the liquids produced by refining coal? Wouldn't this be a natural step in commercialization of this alternative fuel?

Answer: DOE has supported work which demonstrates the production of premium diesel fuels from indirect coal liquefaction which are free of sulfur and aromatics and have a high-cetane number. An effort is underway to produce a large batch of this coal-based clean diesel for engine testing under a joint program between Fossil Energy and the DOE/Alternative Fuels Utilization program tentatively scheduled for mid-1991. The testing will also quantify the blending premium for this coal-based alternative diesel.

QUESTIONS FROM SENATOR BURNS

Coal Research and Development

Question 12: Why is DOE objecting to or resisting the implementation of the programs proposed by Sections 5002 et seq.? Would they interfere with current programs or merely augment them? If the latter, what is the problem?

Answer: DOE is not resisting the implementation of the programs proposed by Sections 5002 and beyond. Nonfuel uses of coal, coal-fired locomotives, and coal fuel mixtures identified in these sections are all important areas and are already part of the existing coal R&D program. Singling out these few coal programs and mandating separate reporting requirements is not conducive to a coherent, priority based coal program. The issue of non-fuel uses should not overshadow the more important fuel uses.

QUESTIONS FROM SENATOR BURNS

Coal Refining

Question 13: How does DOE propose to use coal to decrease our dependence on foreign oil for transportation fuels?

Answer: The DOE is supporting an aggressive research and development program in coal liquefaction with the objective of developing technology for the production of liquid transportation fuels from coal. This program seeks to maximize the use of cost-shared research and development projects with industry to promote technology transfer and insure that the program has an appropriate industrial focus. As a result of these efforts, significant progress has been made in this technology since the early 1980's. The technology now being demonstrated in the program is projected to be competitive with crude oil at $35-$40 per barrel. Improvement potentials have been identified which could lower this to $30 per barrel crude oil equivalent by the late 1990's, assuming a continuation of the research and development program. World oil prices are projected to rise to $30 a barrel or higher soon after the year 2000. Under these conditions then, coal liquefaction could become commercially viable before 2010. We would anticipate significant industrial interest in pursuing commercialization in that time frame, and our projections show that an industry of 1 million barrels per day or more could be realized by the year 2030. As this production comes on stream, it would result in a barrel-per-barrel backout of oil. It is not possible to predict in advance, however, whether it would be domestic or imported oil that would be backed out by any substitute.

QUESTIONS FROM SENATOR BURNS

Coal Refining

Question 14: Why does DOE not currently support programs for coal refining by hydrocracking since that process has been commercially available in the petroleum industry for over 50 years?

Answer: As previously stated in the answers to Question #1 and #2, the Department has supported, and is continuing to support, a substantial program in direct coal liquefaction which utilizes hydrocracking technology similar to that used in the petroleum industry. In this technology, hydrogen under high pressure and a catalyst are used to "crack" the larger soluble molecules to lighter, more valuable hydrocarbons.

QUESTIONS FROM SENATOR BURNS

Coal Refining

Question 15:	What is the definition of "gasification", "liquefaction", "indirect liquefaction", "pyrolysis", "mild gasification", "coal refining"?
Answer:	Gasification is defined as the reaction of coal, oxygen, and steam at high temperatures of 1300-2700° F to produce a variety of products including carbon monoxide, hydrogen, methane, light hydrocarbons, liquids, and tars depending on the gasification conditions chosen.

Direct liquefaction is a process for solvent dissolution of coal under temperatures of 700-800° F and high pressure (2000-3000 psig) utilizing hydrogen to produce a syncrude which may be upgraded using conventional refinery technology to produce specification transportation and heating fuels and petrochemicals.

Indirect liquefaction is a process which utilizes coal gasification to produce a synthesis gas (hydrogen and carbon monoxide) which can be processed with a variety of catalysts to produce transportation fuels e.g., diesel fuel, methanol, octane enhancers, chemicals, and synthetic natural gas.

Pyrolysis is the thermal processing of coal without added oxidant or hydrogen to produce solid, liquid, and gaseous products which may be utilized as fuel or upgraded.

Mild gasification is a low-temperature pyrolysis which produces a suite of environmentally sound value-added liquid and solid products such as formcoke, electrode binders, carbon black, etc. The liquid and solid products from mild gasification may also be used for their fuel value such as contemplated in the ENCOAL demonstration project.

Coal refining is a broad-based term which can be used to define a group of processes which utilize coal to produce a suite of liquid, solid, and gaseous products and/or electricity.

QUESTIONS FROM SENATOR BURNS

Coal Refining

Question 16: How does DOE propose to integrate into its fossil fuel R&D program the refining of all types of coals, just as all types of petroleum are refined?

Answer: The fossil fuels R&D program for refining coal, direct liquefaction, gasification, and mild gasification concentrates on processes that are applicable to all ranks of coal. The applicability of a process to more than one rank of coal is one of the criteria for selecting a process for development or demonstration.

Emissions

Question 17: What is the difference between "reduction" and "control" of emissions?

Answer: The words "reduction" and "control" as used in the context of emissions are essentially the same. Both words denote a lowering of emissions.

THE NATIONAL COAL COUNCIL, INC.
Post Office Box 17370, Arlington, Virginia 22216
(703) 527-1191

April 5, 1991

The Honorable Wendell H. Ford
United States Senate
Washington, D.C. 20510-1701

Dear Senator Ford:

This is to acknowledge receipt of your letter of March 20, 1991, thanking us for testifying before your Subcommittee on Energy Research and Development. It was our privilege and honor to do so.

In your letter, you enclosed questions and requested answers from us to those questions. We are pleased to forward herewith our responses.

The following discusses our responses to your questions:

1. You asked us to ". . . provide for the Committee a listing of the recommendations made by the National Coal Council and the disposition of those recommendations by DOE."

   a) Enclosure (1) entitled "The National Coal Council Recommendations to the Secretaries of Energy" provides a copy of information from each of the Council's reports submitted to the Secretary of Energy over the past five years.

   b) The Council has not felt it appropriate to track the disposition of its recommendations by the Secretary of Energy. Therefore, we respectfully submit that we are not in a position to answer the second part of the first question.

2. a) Enclosure (2) provides a separate listing of our recommendations relating to clean coal technologies.

   b) The National Coal Council has considered it beyond the bounds of its charter to specify the need for specific legislation to enact the recommendations made by the Council from time to time. We have felt that such a determination more appropriately is the purview of the Secretary of Energy. Accordingly, we cannot respond to the second part of this question.

3. In several of our studies, we have predicted that the development and deployment of clean coal technologies has the potential to displace imported energy over the long term. To accomplish this would require economically competitive coal-derived liquids and gases to penetrate the transportation, industrial, commercial and residential sectors. We have not, however, actually quantified the potential displacement amounts - believing this to be too speculative given the range of uncertainties involved.

   The data contained in the appendices of our "Long-Range Role of Coal in the Future Energy Strategy of the U.S." study does show some of the potential for coal growth with concomitant technology development. It does not, however, attempt to predict that specific quantities of imported energy will be displaced by this growth.

   The Energy Information Agency of the Department of Energy did make certain projections and forecasts in a September 1987 report entitled "Opportunities for Using Coal to Replace Imported Energy in Electric Utilities," EIA, SR/EPD/8701. We respectfully suggest that the EIA may have more detailed information of the type you seek.

Again, we welcome the opportunity to provide information relative to your deliberations. If we may be of further assistance, please do not hesitate to contact us. Thank you for calling upon us.

Sincerely,

William Carr
Chairman

ENCLOSURE NUMBER ONE

The National Coal Council

Recommendations

To The Secretaries of Energy

June 1986 - June 1990

June 1986

Clean Coal Technology

GERALD BLACKMORE, *Chairman*
Coal Policy Committee
IRVING LEIBSON, *Leader*
Clean Coal Technology Work Group

THE NATIONAL COAL COUNCIL

Executive Summary

Based on using current and newly developing clean coal technologies, coal has the ability to play an increasingly more important role in our national energy mix. The advantages of this increased role include economic and employment stability in coal producing states, significant reductions of trade imbalance, and increased national energy security. However, expanded use of coal will require resolution of legitimate concerns with acid rain and technological responses to increasingly more stringent governmental regulations.

Clean coal utilization technologies fall basically into three categories: pre-combustion (such as coal cleaning), combustion/conversion (such as fluidized bed combustion or coal gasification), post-combustion (such as flue gas desulfurization), or combinations of several technologies. These technologies are in various stages of development. Many still need to be demonstrated at a scale appropriate for the market before they are ready for commercial implementation.

These technologies were evaluated for a range of end-use applications and a number of potential SO_x and NO_x emission control criteria. The result was thirteen matrix oriented tables that are included within the detailed report and a few basic observations from the analysis of these tables.

- No single technology covers all user needs in a cost effective manner.
- A range of demonstrated technology options are necessary to respond to potential or anticipated emission requirements. The leading technologies in each category depend heavily on the type of coal used, on the restrictiveness of potential emission limits, whether the application is for a new plant or retrofit of existing facilities, and the scale of the application.
- Those technologies evaluated as having the highest relative commercial potential for each scenario are identified in the tables. Each of the following technologies was evaluated to have at least moderate potential for one of the thirteen cases: advanced physical coal cleaning, micronized coal, coal-water slurries, two-stage slagging combustors, sorbent injection, low NO_x combustors, atmospheric and pressurized fluidized bed combustors, coal gasification (with combined cycles), selective catalytic and non-catalytic reduction of NO_x, advanced wet flue gas desulfurization (FGD), dry injection FGD, combined SO_x/NO_x control, direct and indirect coal liquefaction.
- The timing of any new regulatory requirement involving emission limits has an important effect on technology selection. Many of the more promising new technologies have not been demonstrated sufficiently to be considered commercially ready.

Between existing and newly developing technologies, the long term ability exists to provide for the increased clean use of coal. In order to position the nation, the best of the various clean coal technologies need to be demonstrated as rapidly and as completely as possible.

From the National Coal Council's perspective the following conclusions apply:

- Demonstration of the most promising technologies in each category is needed. This will ensure that the most cost effective clean coal technologies are available for site-specific application for the range of potential future emission limits. The time required for development and demonstration mandates swift commitment to these programs.

- Before enactment of new emission standards, new clean coal technologies need to be developed and demonstrated to the extent required for market acceptance. Lowering emission limits arbitrarily with currently available technology options is likely to lead to increased costs for ratepayers and consumers, undesirable waste disposal problems, and an increased dependence on imported premium fuels.
- Current economic conditions negatively impact on the private sector's introduction of new technologies for a variety of reasons. This is an appropriate time for use of cost and risk sharing between government and industry to develop new clean coal technologies. Financial grants by government on a cost sharing basis with industry are likely to produce the most successful and timely projects. The effect will be the long term increased use of coal in an efficient and environmentally acceptable way.

2

Recommendations based on the work of the National Coal Council include:

1. The establishment of an effective coordination mechanism between federal and state programs that will ensure that funding is applied to programs in as broad, but effective, a manner as possible with commitments to multiyear programs. The establishment of this coordination mechanism could be initiated by the Secretary of Energy calling for a conference of governors from coal utilizing and coal producing states along with the heads of affected federal agencies. Because the Department of Energy is administering the largest source of funds for technology development, it should take a leadership role in this coordinated effort.
2. Legislation may be needed in the individual states to generate a portion of the funding required for clean coal technology demonstrations. Furthermore, the electric utilities need to be provided with the pass-through of demonstration costs into the electricity rate base by the state Public Utility Commissions. This needs to include the allowance of returns on capital investment commensurate with participant's risk for the facilities required for demonstration and commercialization of the clean coal technologies, as well as retrofits from oil or gas to coal use.
3. Out of the conference proposed above, a panel of industry executives needs to be established under the Secretary of Energy that is empowered to provide a combined business and technical judgment, guidance, and direction for the Department of Energy's Fossil Energy Budget (including the various clean coal technology programs). We believe such a panel could provide valuable input to the Department of Energy in the prioritization of research efforts in areas of strong commercial promise.
4. The development of an effective demonstration program consisting of appropriately-sized projects to ensure technology acceptance in each area highlighted as most promising is needed. The technology matrix tables have been provided as potential guidelines in the selection of demonstration projects for funding.
5. More stringent emission standards should not be applied without regard for the development and demonstration of appropriate clean coal technologies to allow for cost-effective compliance.

Chapter 2

Government Policies and Clean Coal Use

Recommendations to the Secretary of Energy

- The Secretary should use his office to aid in developing a consistent national energy policy which recognizes the role clean coal use must play in maintaining our future economic growth while ensuring a greater level of energy self-sufficiency and security. The Secretary must then insulate the programs used to develop clean coal technologies from arbitrary changes in directions and funding.
- Appropriately-sized demonstration plants are vital to successful implementation of clean coal technologies. The Federal government, along with state governments, needs to take an active role in sharing the financial and technical risks of bringing clean coal use technologies to commercial fruition. Financial grants by government on a cost sharing basis with industry are likely to produce the most successful and timely projects.
- With future strictures expected on DOE budgets because of the Gramm-Rudman legislation and other deficit reduction programs, innovative methods need to be found to pick up the shortfall in funding available for developing clean coal technologies. The Secretary should take the initiative in exploring the possibility of establishing development consortia which include DOE, the governments of the coal producing states, and major coal users and producers.
- The Secretary should work to convince public utility regulatory agencies that the cost of clean coal use technology research, development, and demonstration will ultimately benefit not only the nation but the utility customers as well. As such, the cost and risk of developing clean coal technologies is a cost of doing business and these costs must be recoverable from the rate payer.
- The Secretary should recommend to the Congress and EPA that emission standards should be revised so that they define only control levels which are linked to health and welfare requirements. The selection of the method of control used to meet these requirements should be left to the coal user.

Coal's Future Role in U.S. Energy Policy

Coal, America's most abundant fossil energy resource, will have to play an increasingly more important part in our national energy mix as our limited supplies of crude oil and natural gas dwindle. Recognizing this, the Department of Energy must take the initiative in educating both the public and private sectors about the role coal will fulfill in maintaining the nation's economic growth while reducing our trade deficit and ensuring a greater level of energy self-sufficiency and security. No less important, Congress and the public must also be made aware that by harnessing new and improved technologies, coal can be used in an environmentally acceptable manner.

One paramount goal of the Department of Energy's education process must be establishment of a consistent national energy policy which recognizes the need for improved clean coal technologies. Once this policy is set, priorities for developing promising clean coal technologies must be selected in conjunction with the private sector, based on industry's willingness to share in the risk and benefits of the work through co-funding. It is critical at this juncture for the Department's educational process to continue. The development of most clean coal technologies will require a multi-year commitment. Working through Congressional subcommittees and interagency liaison groups, DOE must use its influence to help protect the clean coal technology program from arbitrary changes in direction and funding levels, whether by Congressional mandate or changes in laws and regulations. Program stability is the key to successfully developing clean coal technologies and furthering the use of our nation's most abundant energy resource. 22

Industry/Government Risk-Sharing on Coal Technology Development

The key to increased coal use is technology development. For the foreseeable future, coal will be at a relative disadvantage vis-a-vis oil and gas in the areas of transportation and labor. Coal also is at a relative disadvantage to those fuels in combustion and utilization, but its greatest advantages are its domestic abundance and geographic diversity. For these reasons alone, we must increase the use of coal. Although this energy resource is now used in ways that are commensurate with society's environmental and economic requirements, both the challenge and opportunity for increasing coal use lie in developing the technologies which take advantage of coal's inherent pluses and overcomes its minuses.

There are many coal use technologies which offer varying degrees of advantages to the coal user. These advantages most often are dependent upon the site and the coal to be used. Thus, for society to derive the full benefit of this plethora of technologies, most of these processes must be demonstrated. Because these demonstration projects have a significant risk level, government participation is essential. This is a proper role for government and represents effective policy. The U.S. not only profits from this policy by achieving a measure of energy security, it also has a positive effect on the balance of payments and unemployment. Tax revenues also are impacted favorably by increased coal use.

While the demonstration of emerging technologies is vital to the success of clean coal use, it is important to note that the concept of technology demonstration has changed dramatically over the past decade. In the mid-70's, as new technologies were being developed to face the challenge of the OPEC embargo, it was thought that demonstration required fully-integrated, commercial-scale facilities. It has become clear since that time that such expensive, large-scale facilities are not necessarily required to demonstrate the viability of a technology. In most instances, single modules of sufficient magnitude to demonstrate the viability of engineering scaling factors, reliability and maintainability, and environmental acceptability, often are adequate for this purpose. Some processes, particularly in the utility sector, may require larger-scale, fully integrated projects to demonstrate a particular feature, but on balance, a demonstration plant in the 1980's can be a much smaller facility than those envisioned during the 1970's. Also, once these facilities have served their purpose for the nation, they can be abandoned rather than forced into commercialization.

In summary, demonstration plants are vital to the successful implementation of new coal technologies. These demonstration facilities can be modest in size and expense compared to past perceptions. But, an active role by the government in sharing in the cost of the demonstration programs is vital to successful development of technologies. This is because the past history creates concern, the technological risks are significant, the technologies are many and diverse, and the success of a national effort to increase the use of coal is critical to the long-term security of the country.

Clean Coal Technology Funding

As discussed above, the most critical step in developing any commercially viable clean coal technology is the demonstration of key components of that technology on a scale large enough to reduce the risk of commercialization to a level acceptable to the sponsor. Government must share in this risk if the efforts to increase the use of coal in an environmentally sound manner is to bear fruit.

Considering the current political climate in Washington, the availability of DOE funding for an adequate and/or stable clean coal technology demonstration program is tenuous, at best. Concerns about the Federal budget deficit and the sequestering of funds as mandated by the Gramm-Rudman Act will, in all likelihood, result in funding cuts that will cripple this fledgling program, rendering it ineffective. New sources of funds must be found to maintain the thrust of the program if the nation is to have a clean coal option in the future.

Depending on the success or failure of the clean coal technology program, the coal producing states have much to gain and much to lose. A successful program could increase the use of high sulfur coal and result in higher employment levels in the mining sector, an accelerated economy in the states involved, and higher tax revenues. On the other side of the coin, stagnant or reduced coal use because of new or more stringent environmental standards would result in serious damage to the coal mining industry and economies of the coal producing areas. Both the public and private sectors in the coal producing states must be made to realize that they too have a stake in the successful demonstration of emerging clean coal technologies, and because of this, they too must share in the cost and risk of the program. This initiative has already been taken by the State of Ohio which is providing $100 million to be used in coal research and development. Much can be learned from Ohio's example. It is recommended that the Secretary of Energy convene a conference of Governors from the coal producing states to develop demonstration unit funding methods which involve cost and risk sharing by Federal and state agencies along with major coal users and producers.

Public Service Commissions—Recognition of Rate Payers' Risk-Sharing

The public utility regulatory agencies and other responsible governmental agencies must understand and accept that the cost of clean coal use research, demonstration, and development is a cost of doing business that will ultimately benefit the utility customer.

In the recent past, regulatory commissions have been redefining the term "used and useful" for purposes of rate making. This new very narrow definition has resulted in exclusion of all or a portion of conventional power plants from rates because they were in excess of immediate load needs and did not meet a specified reliability criteria. Such actions have resulted in an unwillingness on the part of the power industry to spend money for conventional power projects and has all but eliminated any interest by utilities in contributing monies for technology, research, demonstration, or development beyond the relatively small contributions to industry associations or institutions. This utility withdrawal from technology development is happening at a time when large sums of money are needed for the final demonstration and development of new clean coal technologies. Our country was founded and has grown on the concept that the willingness to take risks brings results, knowledge and new resources. It is imperative that there be a renaissance in regulatory thinking and policy. From the late 1800's to the 1940-1950 period the power industry grew, developed new technology, and provided increasingly reliable service at decreasing rates. The advent of increasing regulation has been a major impediment to the continuing improvement of service and has been a major contributor to the increasing cost of service. A new regulatory formula is needed if the customer is to benefit from developing technologies, especially clean coal technology. That new formula must provide a path for those viable clean coal technologies to proceed through research to commercialization.

Elimination of Technology-Constraining Emission Control Regulations

The Clean Air Act as amended in August 1977 unfortunately signaled a shift away from quantitatively supported national health and welfare based ambient air quality criteria. Administrative definitions of the "best technological system for continuous emission reduction" are now the primary regulatory mechanisms. This change, most evident in the Standards of Performance for New Stationary Sources (NSPS), can be ratcheted up at administrative discretion and tends to discourage productivity and innovation. Conversely, it increases compliance cost by preferentially encouraging one control method relative to others. For example, requiring a percent removal of SO_2 in a flue gas stream has had a major impact on fuel use by discouraging coal cleaning and the burning of low sulfur coal in favor of flue gas desulfurization.

Unfortunately, this regulatory shift does not attack pollution directly but instead reduces the efficiency and increases the cost of production in a few administratively accessible source categories, particularly those depending on coal. The result is wasteful and technically incapable of meeting the health and welfare objectives of the Clean Air Act.

This so called technology "forcing" concept is taken even further under the Clean Air Act. Best Available Control Technology (BACT) is now required in all areas which have already attained the national ambient air quality standards. Here the required control technology is selected on a case-by-case basis by the states but must be at least as strict as NSPS. As a practical matter, such random application of the technology "forcing" concept has proven instead to be technology inhibiting. Even though an unencumbered advanced clean coal technology may demonstrate both economic and environmental advantage, the additional technical and cost penalties associated with locally determined BACT delay or prevent its commercial application. This problem could be overcome by developing emission standards that define only control levels which are specifically linked to scientifically based health and welfare requirements. Selection of the method of control for meeting those requirements should then be left to the user. Such changes would encourage the use of clean coal technologies.

Further, the demonstration of new and innovative technology to reduce emissions and improve productivity should be encouraged by environmental legislation. Today, the potential advantages to the first users of new, clean coal technologies tend to be negated by penalties associated with failing to meet all regulatory criteria throughout their commercial demonstration. This is compounded by the uncertainty that even if successful, the technology may be rendered obsolete by additional administrative regulatory judgments.

Coal Conversion

June 1986

GERALD BLACKMORE, *Chairman*
Coal Policy Committee
WALTER M. VANNOY, *Leader*
Coal Conversion Work Group

THE NATIONAL COAL COUNCIL

Executive Summary

The term "coal conversion" as used in this report refers to the transformation or replacement of existing oil-burning equipment (boilers, furnaces, internal and external combustion engines) to or with coal or coal-derived fuel-burning capability (although oil-burning capability may be retained).

The National Coal Council finds that coal conversion, where it is economically justifiable (where the cost of buying and using coal is less than oil, gas or other energy sources), can contribute significantly to the fulfillment of national policy goals by

(1) Reducing that portion ($50.4 billion) (38 percent) of the $132.1 billion 1985 United States balance of trade deficit which is attributable to imported oil;

(2) Providing for a United States energy mix which will enhance U.S. national security and economic stability by decreasing United States dependence on imported petroleum;

(3) Reducing the overall cost of fuel consumption to the user over the long term and stimulating domestic economic growth which bolsters state and federal tax bases.

Domestic coal reserves and production capacity are more than adequate for the increased use of coal over the long term and hence, will support coal conversion.

Project economics favoring the use of coal is a precondition to coal conversion in the United States. Coal conversion is not economically justifiable unless it results in lower overall costs to the owner/investor of the equipment and/or its customers. Of prime importance then is the need for a substantial, favorable delivered price differential for coal over oil or gas. At the present time, this price differential does not exist due to the rapid drop in oil prices.

However, the National Coal Council assumes that at some future time, coal conversions can become economic. At that time the private sector should be prepared to consider coal conversion. In the meantime, the federal and state governments should remove impediments which have in the recent past hindered a fair economic consideration of that prospect.

As a result of this study, we think that sufficient economic incentive does not exist for coal conversion in the industrial and utility sectors when the delivered price of crude oil falls below the $18 to $25 per barrel range, Gulf Coast, or to a less than $1.25 per mmBtu coal-to-crude-oil price differential. This depends upon the type and amount of conversion, size of the unit or system involved, and the location of the unit. For coal conversions to take place in the transportation sector, the delivered price of crude oil would have to be over $30 per barrel or show an oil-to-coal price differential of $2.00 per mmBtu's.

Prospects for Coal Conversion

The National Coal Council examined the prospects for coal conversion in each sector of the economy. The transportation sector (19.4 quads per year) remains the largest petroleum user, followed by the industrial sector (7.7 quads per year), then the residential/commercial sector (2.6 quads per year), and finally the electric utility sector (1.1 quads per year) (DOE/EIA Monthly Energy Review, December 1985). In light of these petroleum consumption statistics, the National Coal Council's findings on the prospects for coal conversion in each sector are set forth below.

TRANSPORTATION SECTOR

For coal to enter this sector, liquid fuels will have to be obtainable from coal, either in a slurry-micronized and beneficiated form or as chemically-derived liquid fuels, such as gasoline or methanol. Further, an infrastructure for coal-derived liquid fuel distribution and sales (other than for coal-derived gasoline or diesel fuel), such as pipelines, service stations, fuel storage systems, is required for this conversion to take place, coupled with long-term support for research leading to technological breakthroughs in the indirect or direct liquefaction of coal. Certain federal regulations under the Clean Air Act and the Energy Policy and Conservation Act impede the commercial adoption of alternate fuels to gasoline.

2 INDUSTRIAL SECTOR

Boilers consume approximately 2.5 million of the 4.1 million barrels of oil per day consumed by the industrial sector. Replacement of each one million barrels of oil now burned by industrial boilers would result in the use of another 250,000 tons of coal. Because the average industrial boiler capacity is an order of magnitude less than the average utility boiler, coal conversion in this sector is hindered by smaller economies of scale, the need for short-term payouts on capital projects, and the lack of local coal distribution centers which can deliver coal at a price competitive with oil. The capability of switching between fuels (oil/gas/coal) is important in this sector because it permits the operator to select the most economic fuel.

ELECTRIC UTILITY SECTOR

120,500 tons of coal per day would be required to replace current oil consumption (486,000 barrels per day) in the electric utility sector. Although this sector's oil consumption has dropped from 1.75 million barrels per day in 1978 to 486,000 barrels per day in 1985, only about 11 percent of this reduction is attributable to oil-to-coal conversions. The remaining reduction may be attributed to under-utilized capacity. According to the North American Electric Reliability Council, over 193,000 MW of oil or gas generating capacity still existed in 1984, practically unchanged since 1977.

COMMERCIAL/RESIDENTIAL SECTOR

Although this sector consumes 1.4 million barrels of oil per day, prospects for coal conversion with existing coal technologies are limited by economies of scale. For coal to penetrate this market, new clean coal technologies will have to be developed which can overcome disadvantages of scale. The Department of Energy's initiative, through its New Fuel Forms Workshop held in February 1986, to encourage the development of new clean coal technologies which can penetrate this market is the best available program to develop this sector and has the National Coal Council's support.

Recommendations and Conclusions Industrial and Electric Utility Sectors

In the short term, the National Coal Council believes that the primary coal conversion market is in the industrial and utility boiler sectors. The National Coal Council reviewed how federal policies affect the three key factors in the decision to convert to coal use or coal-burning capability in the industrial and utility boiler sectors: (1) Technical Considerations, (2) Environmental Considerations, and (3) Economic and Financial Considerations. The National Coal Council came to the following conclusions and recommendations:

Federal Policies Affecting Technical Considerations

(1) *Recommendation:* The National Coal Council recommends that the Secretary of Energy establish demonstration projects in identified technology areas with emphasis on establishing fuel switching capabilities (oil/gas/coal) as widely as possible.

To reduce the higher capital and operating costs of burning coal and to make coal conversion economically and environmentally attractive requires the development and demonstration of new technologies for coal cleaning and coal utilization. Federal funding, combined with private and state funding, for clean coal development and demonstration projects will be helpful in maximizing coal conversions in the future. Specific technology demonstration recommendations are provided in the National Coal Council's Clean Coal Technology report (June 1986) and are listed below:

- Micronized Coal
- Coal-Water Slurries
- Atmospheric Fluidized Bed Combustion
- Pressurized Fluidized Bed Combustion
- Low Nitrogen Oxide Combustion
- Gasification Combined Cycle

- Advanced Wet and Dry Injection Flue Gas Desulfurization (includes LIMB)
- Combined Sulfur Dioxide and Nitrogen Oxide Removal
- Indirect Liquefaction
- Direct Liquefaction

We believe that clean coal technologies should be developed and demonstrated with emphasis on establishing fuel-switching capability (coal/oil/gas capable) as widely as possible, enabling the user to select the most economic fuel.

(2) *Recommendation:* The National Coal Council recommends that the Secretary of Energy establish a national clearinghouse for the exchange and dissemination of technical information resulting from technology demonstration projects and from other industrial and electric utility coal conversion projects.

Publication of essential information and availability of detailed information about coal conversion projects in the industrial and electric utility sectors and coal demonstration projects which are completed or ongoing could facilitate and encourage consideration of coal conversion by others in these sectors.

FEDERAL POLICIES AFFECTING ENVIRONMENTAL CONSIDERATIONS

In general, facilities converting to coal should meet applicable environmental standards, but coal conversion should not be seen by regulators as an opportunity to require *existing* sources to meet New Source Performance Standards. Environmental permitting should be expeditious and straightforward.

(3) *Recommendation:* The present exemption from Prevention of Significant Deterioration permitting and from New Source Performance Standards for coal converting facilities should be retained within the Clean Air Act and its regulatory framework. Specifically, the Department of Energy definition of "coal capable" under the Powerplant and Industrial Fuel Use Act should be retained and adopted by the Environmental Protection Agency (EPA).

(4) *Recommendation:* The Secretary of Energy, in conjunction with the Administrator of the Environmental Protection Agency, should form a DOE/EPA task force to find ways to streamline the federal/state/local permitting process attendant to coal conversion projects.

The permitting process connected with environmental requirements which must be met by a coal converting facility can take several years. The delays inherent in this process have become a significant cost consideration in making coal conversion decisions and continue to impede energy choices which might otherwise be economically prudent.

(5) *Recommendation:* To demonstrate a coal converting facility's compliance with ambient air quality standards, where the EPA has good ambient air quality data, the EPA should rely upon that data rather than upon modeling. Where good data are not available, the EPA should adopt more realistic modeling assumptions based upon actual operating conditions and experience, including stack height and plant operating rates.

The EPA's reliance on air quality modeling to demonstrate a coal converting facility's compliance with ambient air quality standards can hinder coal conversion. The models and the assumptions required as input, such as stack height and plant operating rates, tend to be overly conservative due to emphasis on "worst case" analysis.

(6) *Recommendation:* The Delayed Compliance Order concept in the Clean Air Act which expired on December 31, 1985, should be extended and included in any revision of the Clean Air Act.

The Delayed Compliance Order procedure facilitated coal conversions in the past. It allowed the facility to save on fuel costs by permitting it to burn coal (when it cost less than oil) with existing pollution control equipment while new equipment was being installed. Fuel savings are passed on to electric customers or used to pay the costs of conversion.

(7) *Recommendation:* The Secretary of Energy should host a national conference of the governors of coal-producing and coal-utilizing states to encourage the states to adopt legislation which will provide incentives for and remove barriers to coal conversion.

(8) *Recommendation:* The exemption from hazardous waste regulation in the Resource Conservation and Recovery Act for high volume utility wastes, including fly ash waste,

bottom ash waste, slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels, should be retained.

This waste has been and can continue to be disposed of and used in an environmentally sound manner throughout the United States under state solid waste regulations.

FEDERAL POLICIES AFFECTING ECONOMIC AND FINANCIAL CONSIDERATIONS

(9) *Recommendation:* The two Federal Power Act provisions for financing and cost recovery, (a) "Construction Work in Progress" in the rate base and (b) Oil Conservation Adjustment, provide economic incentives for electric utility coal conversions and should be retained. 4

(10) *Recommendation:* If federal tax simplification legislation is not enacted and the current tax approach is retained, the federal government should retain the following important provisions of the federal tax code which facilitate coal conversion: (a) the investment tax credit (10 percent on most new capital spending), (b) depreciation and amortization schedules (allowing a tax write-off of capital equipment over a 15-year life and a write-off of pollution control equipment added to existing plants over a five-year period), and (c) the allowance for state and municipality issuance of tax-free bonds to finance pollution control equipment.

Transportation Sector

In the long term, the National Coal Council believes that the transportation sector is a promising coal conversion market. We identified three areas in which federal policies can affect the commercial adoption of coal-derived liquid fuels.

(1) *Recommendation:* The Corporate Average Fuel Economy (CAFE) standards under the Energy Policy and Conservation Act which require a vehicle manufacturer to achieve a minimum average mile-per-gallon performance for all gasoline and diesel-fueled vehicles it produces should be altered.

A standard based upon miles per million Btu's rather than on miles per gallon is required to remove the regulatory bias against fuels like methanol which contain less energy per gallon than gasoline or diesel fuel which may contain more energy per gallon.

(2) *Recommendation:* The Department of Energy should position itself to deal in a timely fashion with the question of whether coal-derived liquids (other than coal-derived gasoline or diesel fuel) and alternate fuel-burning vehicles meet the EPA emission standards.

The EPA regulations under Sections 211(f), 203(a)(3), and 206(a), which generally require specific EPA approval for sale of new fuels and the manufacture and testing of new-fuel-burning vehicles, result in costly and time-consuming permitting processes which hinder the commercial application of new potentially coal-derived fuels.

(3) *Recommendation:* The federal government can provide increased market support for coal-derived fuels (other than coal-derived gasoline or diesel fuel) by expanding its coal-derived liquid fuel program for government vehicle fleets.

Commercial/Residential Sector

(1) *Recommendation:* The National Coal Council encourages the Secretary of Energy to retain and expand programs which move toward development of the clean coal technology necessary for coal to penetrate this market.

Interstate Transmission of Electricity

June 1986

GERALD BLACKMORE, *Chairman*
Coal Policy Committee
LARRY FORGY, *Leader*
Interstate Transmission of
Electricity Work Group

THE NATIONAL COAL COUNCIL

Executive Summary

Coal has been the largest energy source for the generation of electricity in the United States since the dawn of the electric utility industry in the late nineteenth century. It remains so today. Over the past 35 years, the electric utility industry has been the fastest growing sector of demand for U.S. coal, increasing consumption from 92 million tons in 1950 to an estimated 690 million tons in 1985.

While, during the late 1960s and early 1970s, price differentials between coal and other fossil fuels were small enough to induce many electric utilities located on the East Coast to switch away from coal to oil on a large scale, reducing their annual coal consumption by some 30 million tons from 1965 to 1975, the oil shocks of the mid and late 1970s reversed this trend, increasing coal's share of the electric utility industry's energy requirements from a low of 44% in 1974 to a high of 55% in 1985.

Increased reliance on this nation's abundant coal resources has allowed the U.S. to reduce its dependence on foreign oil which, in addition to reducing energy costs to consumers, has benefitted national security, domestic employment and the U.S. balance of trade. From 1978 to 1984, substitution of coal for oil in steam electric generating plants reduced this nation's annual consumption of oil by over 275 million barrels. As a result:

- Coal production in the U.S. increased by 80 million tons per year.
- Total employment in the U.S. increased by approximately 38,000 jobs, including 12,000 coal mining jobs and 26,000 jobs in the service sectors of the economy.
- The cost of oil imports into the U.S. in 1984 was reduced by approximately $7.8 billion.

The interstate transmission of electricity contributes substantially to greater utilization of coal in electricity production. In 1984, at least 50,000 GWH of coal-generated electricity displaced—through power transfers among utilities—about 85 million barrels of oil that otherwise would have been used for electricity production. Thus, nearly one-third of the reduction in oil consumption in steam electric plants from 1978 to 1984 was attributable to "coal-by-wire" power transfers among utilities.

Strong electric transmission networks are an essential prerequisite to the maintaining and enhancing of "coal-by-wire" power transfers, as well as to the achievement of many other benefits in the economy and reliability of power supply. Such networks, once in place, provide additional benefits of assuring the greatest possible flexibility in meeting a wide range of operating contingencies and future uncertainties, particularly during periods of major national or regional upheavals—including sabotage or enemy attack—affecting the availability of generating capacity resources in one or more parts of the country. In view of the above, it is in the public interest to maintain the strongest possible bulk power transmission network throughout the United States.

While the nation's electric utilities planned, built, and now operate the interconnected transmission network that is in place today (which is the strongest in the world), substantial governmental impediments, introduced in recent years, constrain the industry's ability to maintain the strength of the nation's interconnected transmission network through construction of new major transmission facilities. Some of the major such impediments are as follows:

(a) Very lengthy regulatory process for issuing licenses or "certificates" for construction of new transmission lines.

Most states have siting legislation and attendant rules and regulations that apply to the higher-voltage transmission lines. Although the rules differ from state to state, they generally require submission of formal documents on "Demonstration of Need" and "Assessment of Environmental Impact", both of which are subject to public hearings prior to issuance of a license or "certificate" that allows the utility to proceed with construction. The agencies and their subdivisions that can have a voice in this process can number between 50 and 100. Experience suggests that the time required for the application and hearing process—including possible appeals to the courts at local, state, and sometimes federal levels—could well run into five or more years, which is longer than the actual construction time for most EHV transmission lines.

2

(b) Conflicting jurisdictions

Conflicts among local, state and federal agencies in licensing matters can result in extensive delays in authorizing new transmission lines. In the case of "Demonstration of Need," highly parochial attitudes exhibited in many instances translate themselves into the arguments that, if the proposed facility is not going to serve the needs of a local load area, it should not be permitted to be built to serve a remote location. Such arguments are sometimes very persuasive to those charged with granting "certificates" for new transmission facilities.

(c) Lack of institutional continuity in regulatory decision-making

This is a very serious impediment to the construction of major new EHV transmission lines. Today, a strong endorsement of a major power supply project by a regulatory commission at one point in time does not provide any real assurance to the electric utility that the same regulatory commission (with, perhaps, a different membership) would not oppose the continuation and completion of that very project at a later point in time. This may adversely impact the ability of the utility to get the facility placed into the rate base and thus recover its investment in the facility.

(d) Complete lack of incentives for an electric utility to embark on construction of major new transmission facilities.

Current regulatory treatment assigns all the economic benefits of the new facility to the customer, leaving it to the utility to bear all of the risks. Considering the long lead times required to license and build a major transmission facility, and the inherent uncertainties in forecasting the economic, institutional, and attitudinal conditions several years into the future, such risks are very substantial indeed.

Although impediments to the construction of new EHV transmission lines occur primarily at the state and local levels, it is clearly in the national interest to remove, or at least alleviate, such impediments. Unless this is done, and done promptly, future reinforcements to the nation's EHV transmission network will not keep pace with projected future requirements for such reinforcements, thus impinging on the reliability of the nation's electric bulk power supply and limiting the extent to which "coal-by-wire" and other power transactions could be undertaken among electric utilities in the future. The consequences would be detrimental to both electricity consumers and to society at large. It is incumbent upon the federal government—through its Department of Energy—to use its influence and authority to ensure that the national interest is served.

It is our view that existing federal influence and authority could be brought to bear most effectively in the areas set forth below. We, therefore, recommend the following:

1. The Secretary of Energy should declare that it is in the national interest to have in place—and to reinforce as the need arises—strong interstate electric transmission networks, so as to maintain and enhance "coal-by-wire" power transfers among electric utilities and to achieve many other benefits in economy and reliability of electric power supply. The need for such strong transmission networks, and the need for "coal-by-wire" as a means for displacement of foreign oil by domestically produced coal in electricity production, has not diminished as the result of the lower price of oil that is currently being experienced on the world market: while the price of oil may go up or down, this nation's long-term need to reduce its dependence on foreign oil through increased reliance on its abundant, indigenous coal resources remains unchanged.
2. The Secretary of Energy or his representative should intervene or otherwise appear before

state and local regulatory bodies that are considering the construction or siting of transmission lines that have interstate or regional implications. Such interventions or appearances should emphasize the transcendant national interest in the expeditious construction of such lines.

3. The Secretary of Energy or his representative should intervene or otherwise appear before state public utility commissions, when appropriate, to emphasize the need to permit electric utilities fully to recover the cost of constructing interstate transmission lines. Assurance of such cost recovery will eliminate or greatly reduce financial risk as a major impediment to the construction of needed transmission facilities.
4. The Department of Energy should encourage and support the Federal Energy Regulatory Commission (FERC) in its efforts to resist state encroachment upon its jurisdiction over the interstate transmission of electric energy. It is essential to the further development of the interstate and regional power grids that the pricing of interstate power flows remains the exclusive prerogative of the FERC.

Chapter 5

Conclusions and Recommendations

Material presented in the preceding chapters of this report leads to the following conclusions and recommendations:

1. Coal is, by far, the most abundant domestic energy resource in the United States. Its production employs approximately 185,000 workers, with secondary employment of about 450,000.

   It is in the public interest to substitute, to the greatest extent possible, the domestically produced coal for imported oil in electricity production.
2. Interstate transmission of electricity contributes substantially to greater utilization of coal in electricity production.

   It is in the public interest to maintain and, if possible, to enhance "coal-by-wire" power transfers among electric utilities for displacement of imported oil.
3. A strong bulk power transmission network throughout the United States is an essential prerequisite to the maintaining and enhancing of "coal-by-wire" power transfers, as well as to the achievement of many other benefits in the economy and reliability of power supply. The nation's electric utilities planned and built such a network, for the most part during the 1960s and 1970s.

   It is in the public interest to maintain the strongest possible bulk power transmission network throughout the United States.
4. Current indications are that new reinforcements to the nation's bulk power transmission network will not keep pace with projected future requirements for such reinforcements. This is bound to impinge on the reliability of electric bulk power supply and to limit the extent to which "coal-by-wire" transactions could be undertaken among electric utilities in the future. This is so because of serious governmental impediments that have been introduced in recent years to the development of new major transmission facilities. Such impediments take the form of
   - very lengthy licensing procedures for construction of new transmission lines;
   - conflicts among local, state, and federal agencies in licensing matters;
   - lack of institutional continuity in regulatory decision-making, whereby a strong endorsement by a regulatory commission of a major power supply project at one point in time does not provide any real assurance that the same regulatory commission would not oppose the continuation and completion of that very project at a later point in time; and
   - complete lack of incentives for an electric utility to embark on construction of major new EHV transmission facilities because of regulatory treatment which assigns all the economic benefits of a new facility to the customer, leaving it to the utility to bear all of the risks.

   It is in the public interest to remove, or at least alleviate, such impediments.

This can best be done if the federal government—through the Department of Energy—were to exercise its existing influence and authority in the following ways:

1. The Secretary of Energy should declare that it is in the national interest to have in place—and to reinforce as the need arises—strong interstate electric transmission networks, so as to maintain and enhance "coal-by-wire" power transfers among electric utilities and to achieve many other benefits in economy and

reliability of electric power supply. The need for such strong transmission networks, and the need for "coal-by-wire" as a means for displacement of foreign oil by domestically produced coal in electricity production, has not diminished as the result of the lower price of oil that is currently being experienced on the world market: while the price of oil may go up or down, this nation's long-term need to reduce its dependence on foreign oil through increased reliance on its abundant, indigenous coal resources remains unchanged.

2. The Secretary of Energy or his representative should intervene or otherwise appear before state and local regulatory bodies that are considering the construction or siting of transmission lines that have interstate or regional implications. Such interventions or appearances should emphasize the transcendant national interest in the expeditious construction of such lines.
3. The Secretary of Energy or his representative should intervene or otherwise appear before state public utility commissions, when appropriate, to emphasize the need to permit electric utilities fully to recover the cost of constructing interstate transmission lines. Assurance of such cost recovery will eliminate or greatly reduce financial risk as a major impediment to the construction of needed transmission facilities.
4. The Department of Energy should encourage and support the Federal Energy Regulatory Commission (FERC) in its efforts to resist state encroachment upon its jurisdiction over the interstate transmission of electric energy. It is essential to the further development of the interstate and regional power grids that the pricing of interstate power flows remains the exclusive prerogative of the FERC.

Report on Industrial Boiler New Source Performance Standards

GERALD BLACKMORE, *Chairman*
Coal Policy Committee
WILLIAM B. MARX, *Leader*
NSPS Work Group

JUNE 1986

THE NATIONAL COAL COUNCIL

Executive Summary

The Environmental Protection Agency (EPA) is currently developing nationally applicable emission limitations for "industrial fossil fuel-fired steam generators" in accordance with Section 111 of the Clean Air Act. The present regulations require a flat 1.2 LB SO_2/MM BTU maximum emission limitation for all new industrial boilers with a thermal heat input of 250 MM BTU/HR or greater. The draft standards being developed by the EPA would require 90% reduction of sulfur dioxide emissions and a maximum limitation of 1.2 LB SO_2/MM BTU from all new coal-fired industrial boilers which have a heat input greater than 100 MM BTU/HR.

At the request of the Secretary of Energy, the National Coal Council (NCC) convened a work group to analyze and report on the potential impacts of the EPA's pre-proposed industrial boiler standards. The attached report, approved by The National Coal Council on June 3, 1986, is in response to the Secretary's request.

Conclusions

Based on an examination of published EPA documents, consultations with actual industrial boiler operators and manufacturers and other pertinent sources, the following conclusions were drawn.

- The draft regulations would increase the cost of steam from new coal-fired industrial boilers by at least $0.70/MM BTU or roughly $17/ton with existing flue gas desulfurization technologies. These additional costs would cause a significant shift from coal to natural gas use. By 1990, it is expected that 70% of the new industrial boiler capacity above 100 MM BTU/HR heat input would be gas fired, displacing about 5.6 million tons/year of potential coal sales if the draft EPA rules are instituted.
- New technologies, such as fluidized bed combustion, although promising, currently lack sufficient operating data upon which to base New Source Performance Standard regulations.
- The total emissions from new industrial boilers will be relatively insignificant for two reasons:
  - —Under a worst case EPA scenario, the total potential emissions from all new industrial boilers above 100 MM BTU/HR, if left completely unregulated, would amount to less than 1.5% of the total U.S. SO_2 emissions.
  - —Industrial boiler emissions have declined and are expected to continue to decline regardless of any additional federally implemented New Source Performance Standards. Between 1973 and 1983, all U.S. industrial SO_2 emissions have decreased 46%. This reduction is a result of energy conservation, reductions in smelter and other heavy industrial capacity, declining industrial boiler population, the replacement nature of the new boiler market (new boilers tend to replace old ones) and existing state and local emission standards.
- The boiler population segment between 100 and 250 MM BTU/HR deserves special consideration because:
  - a. Only 18% of the aggregate capacity of new industrial boilers falls in this size range.
  - b. SO_2 emissions from this segment will contribute at the most 0.3% of the total U.S. emissions.

c. Capital related costs incurred by this segment are disproportionally higher than the larger boilers due to a lack of an economy of scale.
d. Coal transportation costs are liable to be higher because overall coal consumption is lower and therefore volume shipping savings enjoyed by larger users are foregone.

Recommendations

The NCC recognizes that the EPA is legally compelled to develop standards for new industrial boilers. Therefore, it is recommended that:

2

1. The Secretary of Energy should support the existing flat 1.2 LB SO_2/MM BTU maximum emission regulation for new industrial boilers with a heat input of 250 MM BTU/HR or greater.
2. The Secretary of Energy should *not* support the draft EPA regulations for industrial boilers greater than 100 MM BTU/HR, which includes a mandatory 90% SO_2 reduction.
3. The Secretary of Energy should support a reasonable SO_2 emission standard for new boilers above 100 MM BTU/HR heat input. Between 100-250 MM BTU/HR, the limitation should be established at the point which minimizes both delivered coal costs for the small industrial boiler and overall SO_2 emissions. The level should be *no lower* than 1.2 LB SO_2/MM BTU; 1.6 LB is used for illustration purposes in the report. The exact limitation should be based on a study of the geographic availability of coals with various sulfur contents and associated impacts on delivered coal costs and overall emissions.
4. The Secretary of Energy should ensure that NSPS regulations for new technologies be based upon careful studies of actual commercial units in the applicable size ranges. This is consistent with recommendations made by the NCC Report on Clean Coal Technology.

Reserve Data Base

REPORT
OF

THE NATIONAL COAL COUNCIL

GERALD BLACKMORE
Chairman
Coal Policy Committee

STUART B. EHRENREICH
Leader
Reserve Data Base Work Group

JUNE 1987

Executive Summary

Currently several data bases exist which characterize coal resource and reserve estimates in the United States. The Secretary of Energy has requested that The National Coal Council study and make recommendations concerning the accuracy of the coal reserve data bases and the effect of coal related regulations, laws, and policies on such data bases.

Apparently the current data bases, quantifying the amount of recoverable coal in the United States, termed the Demonstrated Reserve Base (DRB) for purposes of this report, have been calculated using methodologies that appear to overstate the amount of recoverable coal. Furthermore, the existing DRB does not seem to consider the impacts of local, state and federal statutes, regulations, policies, and enforcement agency actions on the amount of recoverable coal in the DRB.

The study requested by the Secretary of Energy was divided into three separate tasks:

1. To analyze the existing data bases for gaps and deficiencies which could produce misleading or inaccurate information critical to making policy decisions;
2. To identify and summarize local, state and federal policies, regulations, and laws which could adversely impact the amount of recoverable coal in the DRB;
3. To attempt to quantify the effects of (2) above on the amount of recoverable coal in the DRB.

Analysis of the existing data bases strongly indicates that the DRB is overstated due to a number of factors. These factors include, but are not limited to, inclusion of unmineable, nonmineable or sterilized coal in the DRB; failure to account for losses due to mining and preparation; failure to account for quality differences between coals; failure to account for geologic complications; and lack of consistency between state and federal agencies' estimation techniques. Certain other factors, such as the addition of newly demonstrated reserves to the DRB, may increase the quantities in the DRB at some future date.

Most laws, regulations and policies at all levels of government have a negative effect on the amount of recoverable coal in the DRB. This effect stems from either an economic consideration, i.e. one in which coal reserves cannot be mined economically, or a physical limitation consideration. The most significant laws impacting the availability of recoverable coal in the DRB are the Federal Coal Leasing Amendments Act of 1976 (90 Stat. 1083, as amended), as administered through the Federal Coal Management Program, and the Surface Mining Control and Reclamation Act (30 USC Section 1201 et seq.). Furthermore, some regulations prohibit the exploration for coal which, *de facto*, prevents reserves from being added to the DRB. Finally, there are pending or proposed regulations which could further limit the availability of otherwise recoverable coal in the DRB.

The intent of this report is not to pass judgment on any particular regulation, but rather is an attempt to objectively analyze and quantify the impact of those regulations directly affecting the amount of recoverable coal in the DRB.

A cursory survey of major coal producing companies indicates that the potential effect of these laws, policies, and regulations could result in the removal of five to fifty percent (5-50%) of the recoverable coal in the DRB which falls under the control of these companies.

From The National Coal Council's perspective, the following conclusions apply:

1. *The actual DRB for recoverable coal is considerably smaller than the 488 billion tons purported in the DRB as published by the Department of Energy in 1984.*
2. *Economical and physical limitations are imposed on coal reserves as a result of certain local, state and federal regulations, effectively limiting the availability*

of the coal in the DRB. Chief among these laws are the Surface Mining Control and Reclamation Act of 1977 and the Federal Coal Leasing Amendments Act of 1976.

3. *State and federal laws, policies, and administrative actions, particularly those dealing with land use, tax the ability of exploration to determine accurately the extent and character of reserves and have further cut off substantial amounts of reserves from development. These in turn severely limit our options in meeting our long term energy needs.*

Recommendations based on the work of The National Coal Council include, but are not limited to, the following:

1. **Better standards for categorizing reserves should be developed and implemented which recognize realistic reserve estimation criteria, mineability and recovery criteria, as well as the impacts of competing land uses. This effort should be coordinated by all parties developing and implementing this policy so that a single reliable data base is developed.**
2. **The Secretary of Energy should establish a high level inter-agency working group to study all current and proposed laws, regulations, and policies concerning the coal industry, and their impact on the ability to fully access coal reserves.**
3. **The Secretary of Energy should initiate a comprehensive survey of all coal producers to obtain an in-depth and detailed view concerning the economic and physical impacts of regulations on the recoverable coal in the DRB.**

Improving International Competitiveness of U.S. Coal and Coal Technologies

Gerald Blackmore, Chairman
Coal Policy Committee

James G. Randolph, Leader
International Competitiveness of
U.S. Coal and Coal Technologies Work Group

THE NATIONAL COAL COUNCIL

JUNE 1987

Executive Summary

Interest in coal as a primary energy source was renewed in 1973 when the Organization of Petroleum Exporting Countries (OPEC) raised world oil prices from $3.00 a barrel to over $11.00 a barrel. This first price shock forced countries to explore alternatives in order to decrease their dependence on oil. New coal-fired generating and industrial plants were planned. In the spring of 1979, another round of increases by OPEC more than doubled the price of oil. Efforts were then accelerated to build new coal-burning facilities and to convert existing oil-burning facilities to coal in both the utility and industrial sectors.

From 1973 to 1985, world coal trade has almost doubled. Although the U.S. coal industry had benefited from this growth, it certainly cannot be described as having dominated it. Indeed, the U.S. share of the world market has slipped, from 28 percent in 1973 to 25 percent in 1985. In 1984, the United States lost its position as the leading exporter of coal to Australia.

The purpose of this study is twofold:

- To provide a better understanding of the factors that determine the position of U.S. coal in relation to its competitors in world coal trade; and
- To recommend both government and industry actions that can be taken to improve its competitiveness.

The discussion is divided into six sections. The first section, TRENDS IN INTERNATIONAL COAL TRADE, reviews international coal trade trends since the oil embargo in 1973. It traces trade volumes, identifies the major markets, the suppliers and their market shares. It also looks at price trends and the significant impact of exchange rate fluctuations on trade patterns. The projected growth in demand over the next decade is presented with particular emphasis on the anticipated growth in developing countries.

THE STRUCTURE OF INTERNATIONAL COAL TRADE, section two, discusses qualitatively commercial trading practices that have emerged over this same period. How is the coal trade business actually conducted? Who are the buyers and the sellers? What do these practices mean for U.S. coal exporters? What can or needs to be done to assist them to compete more effectively, given the trade structure that has emerged?

The third section, COMPARATIVE DELIVERED COSTS AND PRODUCTION COSTS IN MAJOR COAL EXPORTING COUNTRIES, looks at the major cost components of coal production in the United States and compares them with the major competing exporting countries to see where the inherent advantages and disadvantages of competition lie. It identifies certain areas of opportunity for cost reduction in the U.S. industry. Also, by documenting the various cost advantages enjoyed by the other major competitors, it emphasizes how sensitive this country's export standing is to any additional cost burden.

TRANSPORTATION ISSUES AND COMPARATIVE COSTS, the fourth section, examines transportation issues and comparative costs as an extension of the preceding section. It compares the U.S. situation with that of its major competitors, focusing on the inherent strengths and weaknesses of the transportation components of the coal chain for these countries.

Section five, CLEAN COAL TECHNOLOGY AND FINANCIAL ASSISTANCE PROGRAMS: LINKAGE TO COMPETITIVE EXPORT SALES, reviews in broad terms the various programs offered by foreign government export credit agencies to establish how competing foreign exporters are assisted by their governments and explores some areas where existing U.S. financial assistance arrangements can be improved. Research and development is addressed with the linkage of clean coal technologies and financial assistance/foreign aid programs to give U.S. coal exporters a marketing advantage.

The final section, NON-COMPETITIVE INDIGENOUS COAL PRODUCTION— OPPORTUNITIES FOR INCREASED EXPORTS, addresses the issue of trade barriers in world coal trade. A substantial amount of coal consumption in the non-socialist countries, equal to as much as fifty percent of estimated 1986 world seaborne coal trade of 304 million tons, consists of coal produced at costs that exceed the landed cost of coal traded competitively in the world coal market. The countries protecting their own high cost production, by using a variety of subsidies and import restrictions, are identified, and the potential impact on world trade of at least partially opening these markets is explored.

The study's major findings and recommendations are summarized here.

MAJOR FINDINGS

I. Trends in International Coal Trade

World coal trade has almost doubled (91 percent increase) in the twelve years between 1973-1985, due to the increased demand for steam coal used in electricity generation. On the demand side, the Western European countries and Japan have been the dominant buyers, but increasingly, they are being joined by North African, South American and other Pacific Rim countries. The traditional major exporting countries still include Australia, the United States, South Africa, Poland, Canada and the U.S.S.R. (in descending rank order), but they have recently given up part of the market to two new entrants—Colombia and the People's Republic of China.

Exchange rate fluctuations in the past ten to twelve years have had a significant adverse impact on the competitive position of U.S. coal. Currency relationships *between exporting* countries, rather than between importing and exporting countries, contribute to greater or lesser price competitiveness for one exporting country vis-a-vis another. In the period 1973 through 1986, continued devaluation of the Australian dollar, the South African rand and the Canadian dollar versus the U.S. dollar, alone, caused deterioration of U.S. price competitiveness of 69 percent against South Africa, and of 53 percent and 28 percent, respectively, against Australia and Canada.

Growth on the order of three percent per year through the year 2000 is projected for world coal trade. This growth is attributable primarily to increasing demand of steam coal imports in Asia and Western Europe. Developing countries will look to coal to supply their growing energy requirements. U.S. exports are expected to increase as total world coal trade expands. However, the United States will face even greater competition as new low cost producers, such as Colombia and the People's Republic of China, expand their coal exports.

II. The Structure of International Coal Trade

Seaborne trade of steam coal in substantial volumes in recent years has brought to the market new buyers, new sellers and new exporting countries. Its development has brought *new* buyers in traditional metallurgical coal importing countries, *new* buyers in newly-importing countries and *new* sellers from traditional and two *new* exporting countries. Among producers, transporters and consumers, the rising scale of facilities in the form of new mine developments, port handling facilities, larger vessels and power generating capacity has increased the level of risk by raising the level of capital requirements from the front to the back end of the coal chain. At the same time, credit-worthiness of many new buyers provoking this chain of investments is open to question. The combination of larger capital requirements and higher commercial and political risk implies a larger role for governments in providing the financial assistance without which these projects would not go forward.

As world steam coal trade has increased in recent years, various governmental entities of other major exporting countries have provided financial assistance for coal-burning installations in order to facilitate export coal sales. Neither the U.S. coal industry nor the relevant government agencies have adequate intelligence on the range and scope of the assistance offered by the competing countries and the trends in prevailing financial practices.

III. Comparative Delivered Costs and Production Costs in Major Coal Exporting Countries

The United States is generally at a disadvantage with respect to delivered costs on a dollar per million BTU delivered basis. Low cost producing countries such as Colombia, Australia and South Africa have the economic advantage.

Foreign exporting countries are not constrained by the same major cost components of coal production that are found in the United States. Black Lung taxes are not paid by other major exporting countries, for example. Foreign competitors generally do not have regulations as restrictive as those in the United States affecting longwall mining, a cost-effective method in producing coal.

IV. Transportation Issues and Comparative Costs

The United States is inherently disadvantaged by long inland freight distances between mines and ports. Transportation is a greater factor in the competitiveness of U.S. coal than it is for other countries. The relative lack of deep-draft harbors in the U.S. is not presently a handicap, but could become so if world-wide coal trade expands rapidly.

Other countries exercise greater governmental investment in and control of transportation of coal exports, both of which may afford those countries more control over the entire coal export chain in their pursuit of national export objectives.

V. Clean Coal Technology and Financial Assistance Programs: Linkage to Competitive Export Sales

Foreign governments of exporting countries can play an increasing role in facilitating export sales with financial assistance programs as the demand for steam coal increases. Some major coal exporting countries, namely Australia, Canada and South Africa, are party to export credit agreements intended to standardize foreign assistance practices that governments use chiefly to help win businesses for exporters. Securing good and timely information on what all competitors are doing, and responding flexibly to changing practices, will become increasingly important as the trade stakes get larger.

Important national security interests are served by promoting selection of the coal option in developing countries. The United States, as one of the largest markets for, and developers of, clean coal utilization technology, can offer developing country customers state-of-the-art technology to meet their power generation needs. Opportunities exist to link such equipment sales with fuel sales.

VI. Non-Competitive Indigenous Coal Production—Opportunities for Increased Exports

The cost of producing some 100-150 million tons of coal in six major coal-consuming countries in the non-socialist world is underwritten in some form, either directly or indirectly, by their respective governments. Were this indigenous production reduced by one-third, in favor of imported coal, world seaborne trade (estimated at 304 million tons in 1986) could experience an increase of more than fifteen percent.

The U.S. government agencies involved in monitoring and promoting free and open world coal trade do not have adequate resources to perform effectively. At least three U.S. government agencies—the Office of the Special Trade Representative, the U.S. Department of State's Office of Energy-Consuming Country Affairs and the U.S. Department of Commerce—are, in varying degrees, active in promoting open world coal trade. But the agency most directly responsible for trade strategy and negotiations, the Office of the Special Trade Representative, has only one person assigned to energy issues, and that person is charged with covering every aspect of the energy arena from petrochemicals to oil, gas, electricity, uranium, fertilizers, basic inorganic chemicals, other natural resources and finally, coal. This allocation of human resources is not adequate.

Recommendations

1. **COAL SHOULD BE ACCORDED A HIGHER PRIORITY IN U.S. TRADE POLICY IN ORDER TO EXPAND ITS CONTRIBUTION TO THE U.S. BALANCE OF TRADE.**

   Coal already makes an important contribution to the U.S. trade balance and, in view of the size and efficiency of the U.S. coal industry, is capable of expanding its contribution significantly. Developing a comprehensive set of coal trade polices to reduce trade barriers and other practices that restrict free trade is a first step that must be taken to achieve this objective. The next step is the inclusion of coal trade issues in broad U.S. trade negotiation strategy. Industry and government trade negotiation representatives should meet regularly to exchange information and plan near- and long-range negotiation strategy.

2. **INDUSTRY AND GOVERNMENT SHOULD WORK TOGETHER IN THE PURSUIT OF NEW MARKET OPPORTUNITIES AND DEVELOPMENT OF AGGRESSIVE TRADE NEGOTIATION STRATEGIES.**

   The implementation of the foregoing recommendation requires accurate, timely and comprehensive economic and market intelligence to project market development and to understand prevailing foreign governmental policies and commercial trading practices. Coordinating the gathering of such information by industry and government is essential.

3. **UNITED STATES TRADE POLICY SHOULD RECOGNIZE THAT A REDUCTION IN COAL TRADE BARRIERS IN MAJOR COAL IMPORTING COUNTRIES COULD RESULT IN EXPANDED U.S. COAL EXPORTS AS THE U.S. CAPTURES A SHARE OF RESULTING INCREASED IMPORT DEMAND.**

   The accelerated reduction of these coal trade barriers should be given higher priority in overall U.S. international trade strategy, thereby making clear to major coal importing countries that such a reduction is an important component of the trade relations with our major trading partners. In general trade discussions, the United States should promote the view that barriers to increased international coal trade create a major inefficiency in the world economy. These inefficiencies cost energy consumers billions of dollars annually and deny markets to efficient competitors in the United States and elsewhere. Discussions held by the United States with importing coal countries should focus on the competitive advantages of U.S. coal relative to subsidized domestic production.

4. **THE UNITED STATES SHOULD CONSIDER THE IMPACT OF EXCHANGE RATE FLUCTUATIONS BETWEEN BOTH MAJOR TRADING PARTNERS AND COMPETING EXPORTERS, (AUSTRALIA, SOUTH AFRICA AND CANADA), AS THESE RATES HAVE AN IMPORTANT BEARING ON U.S. COMPETITIVENESS IN WORLD COAL MARKETS.**

   The adverse impact of these fluctuations represents a cost to the U.S. coal industry and to the U.S. trade balance in terms of lost export sales. This cost should be quantified, along with other adverse effects of an international monetary system that has permitted such volatility in exchange rates in recent years, as the Federal Government formulates its position on international monetary policy.

5. **THE UNITED STATES GOVERNMENT CAN AFFECT U.S. COAL COMPETITIVENESS BY ADDRESSING THE COST OF PRODUCING COAL. IT IS OF CRITICAL IMPORTANCE THAT THE TAX AND REGULATORY BUR-**

DEN ON THE U.S. COAL INDUSTRY BE HELD TO THE MINIMUM, CONSISTENT WITH SOUND RESOURCE AND ENVIRONMENTAL MANAGEMENT AND EQUITABLE TAX POLICIES.

The level of royalty rates should be reviewed. High federal rates may be detrimental because other leases typically have lower rates and would be favored for exports. Regardless of the rate, federal royalties should be calculated on the coal's value net of all other taxes and fees. Regulations which discriminate against longwall mining should be changed.

6. **THE FEDERAL GOVERNMENT AND THE COAL INDUSTRY SHOULD PURSUE A BROAD, INTEGRATED AND COORDINATED STRATEGY TO PROMOTE THE USE OF COAL IN DEVELOPING COUNTRIES FOR POWER GENERATION IN THE INTEREST OF NATIONAL SECURITY AND EXPANDED COAL EXPORTS.**

In the past decade, the total primary energy requirements (TPER) of developing countries have grown 5.3 percent annually, while the TPER in OECD (Organization of Economic Cooperation and Development) countries have grown 0.8 percent annually. In most developing countries, oil dependency is still high. Components of this policy should include the use of foreign aid and technical assistance to support coal-fired projects.

7. **FURTHER FUNDING BY THE U.S. GOVERNMENT AND PRIVATE INDUSTRY OF RESEARCH AND DEVELOPMENT EFFORTS FOR CLEAN COAL TECHNOLOGIES WILL CONTRIBUTE TO INCREASED COMPETITIVENESS OF U.S. COAL EXPORTS.**

The "packaging" or "linkage" of new technologies that have been demonstrated with U.S. coals provide exporters with a marketing advantage. In addition, clean coal technologies which can utilize higher sulfur coals will increase demand for these lower cost coals from the United States that are currently demand-limited. Coal producers and suppliers of coal equipment and/or technology should coordinate export marketing activities to provide for packaging and linkage arrangements.

More responsive and internationally competitive financial assistance programs would also enhance the opportunities for both U.S. coal producers and suppliers of equipment and/or technology.

8. **THE UNITED STATES GOVERNMENT SHOULD ASSESS THE EXTENT TO WHICH TRANSPORTATION POLICIES OF COMPETING COAL EXPORT COUNTRIES IMPACT U.S. EXPORTERS.**

By studying how competing countries subsidize, organize and regulate their transportation systems, advantages and disadvantages for U.S. exporters can be determined. This information can then be utilized in international negotiations.

9. **THE FEDERAL GOVERNMENT SHOULD CONTINUE TO PURSUE POLICIES WHICH FOSTER COMPETITIVE SYSTEMS FOR THE INLAND MOVEMENT OF EXPORT COAL FROM MINE TO PORT AND AVOID POLICIES WHICH INCREASE FREIGHT OR PORT COSTS.**

Encouraging a coordinated marketing effort on the part of both coal producers and transporters would be a positive first step.

10. **PRIVATE ENTERPRISE AND THE FEDERAL GOVERNMENT NEED TO DEVELOP MORE SOPHISTICATED AND BETTER INTEGRATED INTERNATIONAL FINANCING METHODS TO RAISE THE CAPITAL REQUIRED FOR THE SCALE OF INVESTMENTS ASSOCIATED WITH NEW COAL-FIRED POWERPLANTS IN COAL IMPORTING COUNTRIES.**

For industry, this would include long-range packaging of coal utilization equipment and fuel sales. For government, it would mean integrating various financial assistance programs, in conjunction with private industry, that would meet what is currently being offered by governments of competing exporting countries.

Innovative Clean Coal Technology Deployment

November 1988

IRVING LEIBSON, *Chairman*
Coal Policy Committee
KURT E. YEAGER, *Leader*
ICCT Deployment Policy Work Group

THE NATIONAL COAL COUNCIL

Executive Summary and General Findings

It is increasingly clear that the energy needs of the industrial nations together with the legitimate economic aspirations of the developing world will depend on significant increases in world coal consumption. For this to occur, it is essential that a concerted effort be undertaken to develop and deploy more environmentally and economically effective technologies for the use of coal. U.S. leadership in this effort is consistent with its national security and commercial interests, and its responsibilities as a major coal producing and using nation.

Coal is the focus of two independent and conflicting national policy agendas—energy and environment. As the most abundant domestic fossil energy resource, it is essential to the U.S. economy today and to the nation's future energy security. At the same time, however, the nation has a deep and continuing commitment to a clean environment which has historically conflicted with coal use.

The national interest demands prompt resolution of this conflict. Yet how? The National Coal Council finds the accelerated deployment and early commercial application of innovative clean coal technologies (ICCTs) to provide the most cost effective, long-term answer. This initiative capitalizes on U.S. experience and world leadership in coal utilization research.

ICCTs offer the potential to utilize coal in a more cost-effective and environmentally efficient manner than by existing means. The principle guiding ICCT development is that sustained environmental improvement will only be effectively achieved when emission reduction and cost reduction complement each other. ICCTs respond to the environmental consensus of society while controlling the cost of energy and keeping its supply secure. They also offer an important foreign trade opportunity, and are essential to U.S. coal technology leadership in the face of rapidly growing global competition.

ICCTs must be commercially proven and broadly available during the next decade to meet both the requirements of existing and potential environmental policies, and the challenge to the nation's power supply and industrial capabilities. ICCTs must be deployed in this window of time to avoid committing the market to existing technology with consequent negative impacts on energy cost and productivity, or shifts to less dependable energy sources.

In order to achieve this objective, private industry has spent more than $1 billion to develop to the point of demonstration the suite of technologies now grouped together as ICCT. The primary goal of government participation should be to protect and facilitate this industry-led effort through the risks of commercial maturation.

If ICCTs are to be successfully deployed over the next decade, then the technical, commercial, environmental, and regulatory constraints to further private sector initiative must be addressed. At present, the short-term alternatives are too attractive, and the risks are simply too large for individual companies or industries to commit to ICCT deployment while still meeting obligations to shareholders, investors, ratepayers, or other stakeholders.

The primary basis for private industry support of ICCT is to increase the available clean energy choices and to reduce costs, thus increasing profitable markets for coal and its resulting products and services. There is particular concern that this goal may be compromised by mandating additional emission reduction requirements whose magnitude, timing, and technology requirements would restrict the opportunity and incentive for ICCT deployment.

The status of the federal budget and concern for the international competitiveness of U.S. industry argue strongly for new incentive-based policies which emphasize economic efficiency in environmental protection. The appropriate government response is to act in a proactive manner to accelerate market-driven innovation, remove unnecessary barriers, provide appropriate and equitable incentives, and catalyze private sector-managed collaborative efforts that are required for competitiveness in a global market.

Completion of the Department of Energy (DOE)-cosponsored ICCT Demonstration Initiative is an

essential step in reducing the risks associated with ICCT deployment. These cosponsored projects represent a logical extension into collaborative technology development and commercialization on a national scale. The value goes well beyond that of the individual projects.

Beyond the DOE-cosponsored ICCT Demonstration Initiative, government action should emphasize removal of disincentives to:

- Cost-effective actions which sustain the nation's remarkable environmental progress over the past 15 years.
- Timely investments in new industrial and electricity-generating capacity. Of particular importance is prompt cost recovery by regulated utilities.

State government encouragement and support for ICCT development and deployment is an essential ingredient. This is underscored by the fact that nearly 80 percent of all rate regulation of electricity occurs at the state level. In addition, ICCT siting decisions are primarily made at the state level. Thus, assurance of cost recovery, which has historically been fundamental to utility investment, is dependent on state actions. State regulatory commissions in particular should encourage ICCT investments that promise lower life-cycle costs and, thus, lead to reduced customer costs in the long run.

State support for ICCT deployment is in keeping with the state role of maximizing the energy choices and economic well-being of its citizens. States are increasingly complementing federal participation by using their unique capabilities to reduce state or local taxes and provide grants or other active assistance.

An initiative as potentially far reaching as ICCT deployment also requires broad public support. The general public must agree with the importance of ICCT to social and economic well-being. Essential to this goal is implementation of a series of successful ICCT demonstration projects supported by an effective public relations and consensus-building campaign involving the broad set of private and public interests. The Secretary of Energy is a necessary catalyst for this effort.

Public perceptions concerning energy in general, and coal in particular, have been influenced by the nation's historic policy patterns: during periods of energy "crisis" when petroleum supply/cost is threatened, energy policy turns to coal as an abundant fuel resource and a useful source of geopolitical power to offset strategic vulnerability from petroleum dependence. Unfortunately, none of these initiatives has been consistently pursued; however, restrictive regulations have accumulated during the more frequent periods when energy supply has not been a political issue. A public/private joint venture to accelerate ICCT deployment provides a highly visible and lasting opportunity to reverse this policy trend.

General Findings

The general findings of the Work Group concerning deployment of ICCT are summarized as follows:

1. Coal's public image has improved as technological advances and environmental progress have protected occupational health and substantially reduced the amount of emissions from coal utilization. Successful deployment of ICCT is essential to maintaining this progress for the nation's most abundant fossil fuel resource.
2. The ongoing DOE-cosponsored ICCT Demonstration Initiative can provide the essential risk sharing to permit the private sector to confidently determine, through multiple projects, the commercial application envelope for the array of promising ICCT options. Its success as a foundation for deployment will depend on the DOE continuing to participate throughout the demonstration initiative as an investor in projects initiated and managed by the private sector.
3. The collaborative, joint venture approach to the DOE-cosponsored ICCT Demonstration Initiative has been essential in stimulating the market forces that ultimately determine the commercial potential of technology purchased and used by the private sector. These new DOE management and procurement practices have established closer cooperation and credibility for these joint government/private sector development and commercialization efforts.
4. The technology developer/supplier and user must assume a significant risk that ICCT can be deployed successfully and achieve commercial acceptance. This challenge is encountered with the commercialization of any new process, but is especially acute for ICCT deployment because it must be carried out at commercial utility and industrial scale. When combined with the unusually volatile nature of the energy market, it represents an extraordinary financial challenge for the private sector. This challenge becomes especially difficult if the ability to recover the required financial commitment is uncertain because of regulatory or other governmental actions.
5. Other nations have developed targeted industry strategies that involve government-industry consortia designed to capture market share in global markets. Coal utilization and related power generation equipment is one such targeted industry. The strategy involves cooperative R&D, highly leveraged investment with low cost capital, import restrictions, and export sub-

sidies. In this environment, U.S. antitrust laws are failing to promote competition and efficiency. Many well-intended regulatory laws also require selective modification to make them less anti-competitive, and patent and trademark laws need to be strengthened.

6. The demonstration and deployment of ICCT will take time. Even after a technology becomes available for confident commercial use (see Figure 2, p. 19), an additional five to 10 years or more—depending on the complexity of the technology and the scope of the market—may be required before it reaches its full commercial potential. This time frame must be recognized in establishing regulatory compliance schedules if ICCT deployment is to proceed effectively.
7. ICCT deployment policy should distinguish between two fundamentally different technology applications: ICCT retrofit emission controls intended to respond to potential environmental policies affecting existing plants, and strategically more important new plant and repowering ICCT systems. The former typically serve to reduce the cost of compliance with air quality regulation, while the latter have the potential to improve the productivity and economics of coal use with greater environmental control capabilities which consider water and solid waste, as well as air impacts. As a result, different government actions may be required to facilitate deployment.
8. ICCT deployment will be encouraged if environmental regulations utilize market incentives providing maximum opportunity to choose among compliance alternatives and avoid biases in favor of specific solutions which may mask the true cost of compliance decisions. The potential cost savings to the nation can be substantial, reaching an expected $3 billion/yr by the end of the century alone. ICCTs will also support increased efficiency in coal utilization and therefore contribute to moderating growth in the atmospheric concentration of greenhouse gases, particularly carbon dioxide.
9. Developing countries will increasingly look to coal to supply their growing energy needs. The result is a likely doubling in world coal consumption to seven billion tons annually by 2010. Technology to support this demand growth will be an area of intense global competition among the industrialized nations. ICCT will be used if it is available, reliable, and if competitive financing packages can be arranged. Prompt ICCT demonstration and deployment will be an important national asset in this competition. If even half the world's expected expansion in coal utilization for power generation used U.S.-manufactured equipment, the value would be about $35 billion/yr by 2010.
10. A successful national ICCT demonstration and deployment initiative can ultimately provide a coal-processing technology foundation capable of refining and synthesizing a wide range of products including electricity, transport fuels, and chemical feedstocks, while recovering essential mineral credits. Thus, ICCT has the potential to provide a secure energy and resource foundation for the United States and a fundamental economic capability for the developing world as well.

Recommendations

The essence of the Work Group's recommendations is that federal and state governments should aggressively support, in the national interest, the commercial deployment of ICCT.

These recommendations involve aspects of energy, tax, environmental, and trade policies, permitting, regulatory incentives/disincentives, and public education.

Implementation of these recommendations will require cooperative efforts by a number of public and private entities to resolve the risks the private sector faces in successfully accomplishing deployment. These are:

- Technical risks involving performance and reliability at specified levels, duration, and cost.
- Commercial risks resulting from uncertain future energy, trade, and regulatory policies and resulting market conditions.
- Environmental policy risks which may mandate currently available technology or compliance to levels and within time frames which effectively preclude ICCT or negate its intent.
- Regulatory uncertainties that expose investors to unexpected, after-the-fact financial risks without compensating opportunity for financial reward.

Following are the Council's recommendations:

1. **COMPLETE THE ONGOING DOE-COSPONSORED ICCT DEMONSTRATION INITIATIVE AS PLANNED.**

Complementary demonstrations of the most promising technologies which address the range of designs, coals, and operating variables faced by coal users are necessary to confidently map ICCT's commercial application envelope. The phased nature of this initiative encourages cost-effective targeting of resources and recognizes the reduction in risk achieved through successive projects.

In order to achieve the greatest national benefit the initiative should:

- Provide developers with greater protection of their proprietary technology based on their cost sharing participation.
- Pursue parallel paths of providing advanced technologies suitable for new plants, as well as retrofit/repowering options for existing facilities.
- Encourage technologies which emphasize increased energy efficiency and control, minimization, or utilization of liquid and solid waste by-products, as well as air emissions. The result will be increased opportunity for long-term environmental protection and commercial viability.
- Encourage technologies suitable for modular construction and plant design standardization to shorten lead times and reduce the risks of installing new industrial and generating capacity.

2. **CLEARLY DEFINE THE SCOPE AND EXTENT OF ICCT "DEPLOYMENT."**

This would go far to alleviate concern over government participation. The goal of national ICCT deployment policy should be to advance commercial maturity as quickly as possible for the broadest possible market. This requires that the various promising ICCT technologies be applied under enough varied circumstances to permit industry to make confident decisions about the technical and economic merits of each, as well as its commercial availability, quality, and performance.

3. **ACTIVELY ENCOURAGE, AT THE STATE LEVEL, UTILITY AND INDUSTRIAL PARTICIPATION IN ICCT DEPLOYMENT EFFORTS BY ALLOWING OR PROVIDING:**

- Full construction work in progress (CWIP) in rate base, and/or accelerated depreciation, both of which allow a company to recover capital investment more quickly.

- Incentive rate of return to recognize that riskier plants—like demonstrations of new technologies—may require higher return to compensate for higher risks. This should consider risk adjustments to the authorized rates of return for utilities deploying ICCTs.
- Preconstruction assurance that expenditures will be considered prudent within a phased prudency review mechanism that establishes agreed-upon expenditure caps for each corresponding phase of the project.
- Appropriate expense treatment for contributions to collaborative industry efforts and R&D costs, including equipment used solely for R&D purposes.
- Regulatory modifications to allow ICCT to receive treatment now only accorded existing cogeneration and renewable energy sources. This could include, for example, investment tax credits for the necessary equipment. Such modifications should also encourage and expedite ICCT deployment by industrial and other nonutility coal users, recognizing that these companies can be a valuable source of technology, funding, and commercial leadership.

4. **ENSURE THAT AIR QUALITY LEGISLATION PLACES PRIORITY ON SUSTAINING THE REMARKABLE NATIONAL PROGRESS MADE OVER THE PAST 15 YEARS IN EMISSION REDUCTION WITH THE LEAST IMPACT ON COST AND PRODUCTIVITY BY PROVIDING:**

- Sufficient compliance time for ICCT deployment so the market can confidently choose the least-cost solutions from among an array of emission control options. An effective strategy should be designed to ensure the availability of the necessary options to the market, not to artificially restrict that market.
- Maximum practical freedom of choice among alternatives for meeting defined emission control objectives without biases in favor of specific "equipment" solutions. Such biases have proven to both inhibit technology development and increase compliance cost.
- Encouragement of risk management-based environmental policies that enhance energy competitiveness as well as environmental protection. Such policies provide a valuable cost/benefit framework for achieving public understanding and consensus.
- The resources necessary to confidently measure the energy balance of the earth as the essential foundation for understanding the greenhouse effect and any related energy policy implications.

5. **LOWER FEDERAL AND STATE ENVIRONMENTAL REGULATORY BARRIERS TO WIDER USE OF ICCT OPTIONS BY PROVIDING:**

- Flexible source emission reduction targets, which would include "bubbling" to reduce costs by allowing averaging of emissions over all facilities in a state or region, and tradable emission permit systems, provided that ambient air standards are maintained.
- Tonnage reduction compliance standards, allowing utilities to receive full credit for gross emissions reductions achieved by demand-reducing strategies.
- Expanded Innovative Control Technology waiver provisions in the Clean Air Act, and revised requirements so that waivers may extend beyond four years after startup.
- Interstate air quality management coordination to encourage neighboring states to implement cooperative strategies for emissions reductions, including emissions trading among states. This should consider compensation to the entities responsible for establishing the tradable environmental margins.

6. **MODIFY FEDERAL, STATE, AND LOCAL ENVIRONMENTAL PERMITTING PROCEDURES TO EXPEDITE AND ENCOURAGE ICCT DEPLOYMENT, AND PROVIDE A PERMITTING REFERENCE FOR CONSISTENT AND UNIFORM APPLICATION OF FEDERAL REGULATIONS.**

Key points to be addressed include the following:

- "Grandfather" ICCT installations from further emission reductions for a period of time which recognizes the investment made in the installation. Such safe harboring provisions should be linked, for example, to the depreciation period of the installation.
- Revise Environmental Protection Agency (EPA) regulations to prevent voluntary modifications from triggering even tighter controls at plants which already have an emissions reduction program.
- Allow existing sources currently in compliance with regulations to apply for innovative technology waivers in order to improve cost

and integrated environmental control performance.

- Develop a uniform federal and state permitting procedure for technologies which promise to reduce emissions at lower cost.

7. CONDUCT AN ICCT PUBLIC EDUCATION AND CONSENSUS-BUILDING CAMPAIGN.

The Secretary of Energy should catalyze the process by bringing together the key opinion leaders from the public and private sectors to focus and implement this effort. The steps in the process are:

- Identify the ultimate targets and key opinion leaders
- Shape the message for each market
- Identify stakeholders and spokespersons
- Communicate the message

Primary goals of this program should be to communicate the results of ICCT demonstration programs and the industrial commitment to their success, promote the economic and environmental advantages of the technologies, and encourage a consensus on expanding the environmentally benign use of the nation's most abundant fossil energy source. Such a campaign must recognize and overcome the adversarial conditions which have inhibited a workable consensus on coal. This will require credible involvement by all public and private stakeholders.

8. PROVIDE, WHERE APPROPRIATE, FEDERAL AND STATE ECONOMIC INCENTIVES TO ACCELERATE ICCT DEPLOYMENT WITHOUT DISTORTING THE ENERGY MARKET.

These could include investment tax credits, accelerated depreciation (over shorter periods than under present law), and increases in existing caps on tax-free industrial development bonds now available to states. These types of incentives would reduce the cost of ICCT application for private sector facility owners and customers, thereby encouraging application of technologies chosen by the user.

9. REMOVE RESTRICTIONS ON COLLABORATIVE TECHNOLOGY DEVELOPMENT AND DEMONSTRATION INVESTMENTS BY COMMERCIAL COMPETITORS.

This recognizes that industrial competition is increasingly international in nature, and increasingly demands resources exceeding those of individual companies. The ability to maintain the nation's industrial economic base in this global marketplace depends on the formation of national "arsenals of innovation" which can pool public and private investment to share the risks of technology commercialization. ICCT deployment provides a valuable prototype for such national collaborative efforts, which have also been aided by recent modification to anti-trust laws.

10. ESTABLISH A BIPARTISAN COAL AND RELATED TECHNOLOGY EXPORT POLICY COORDINATING COUNCIL UNDER THE AUSPICES OF CONGRESS AND THE PRESIDENT.

This council would draw its membership from the private sector, from various industry associations, and from the Departments of Energy, Interior, Commerce, State, and Treasury. It would identify decision makers, market conditions, and specific needs in other countries; recommend specific steps to facilitate the export of U.S. coal and coal-related technology; report on any coal-related discrimination practices by other countries and recommend potential remedies, and note any positive steps being taken by these countries that the United States could adopt.

11. REVIEW AND MODIFY APPLICABLE FEDERAL LAW, AS APPROPRIATE, TO PERMIT THE U.S. COAL INDUSTRY TO FORM TRADING COMPANIES FOR THE EXPORT OF COAL AND COAL TECHNOLOGIES.

These trading companies should have access to Export-Import Bank financing, the ability to finance coal-related construction projects in foreign countries as part of the ICCT deployment strategy, and should be empowered to engage in bartering transactions to accommodate variations in exchange rates.

The Use Of Coal In The Industrial, Commercial, Residential, And Transportation Sectors

Irving Leibson, Chairman
Coal Policy Committee

Joseph J. M. Plante
Work Group Chairman

THE NATIONAL COAL COUNCIL
DECEMBER 1988

Executive Summary

The electric utility sector has made significant strides in reducing its consumption of petroleum products and increasing its consumption of coal to generate electricity; other energy consuming sectors have not. These nonutility sectors, namely the industrial, commercial, residential, and transportation sectors, are an integral part of our society. As such, any disruptions in the supply of energy sources which fuel these sectors would send serious reverberations throughout the economy. This report examines these nonelectric utility sectors and identifies opportunities for coal/coal-derived fuels to replace other fossil fuels.

Petroleum products represent the single largest fuel source used in this country. The transportation sector alone consumes nearly two-thirds of the oil used. Increasing reliance on imported oil to meet the demand for petroleum products places the nation at risk and susceptible to a foreign supply disruption. Coal/coal-derived fuels can afford an energy alternative which will lessen the nation's dependence on imported oil. This study does not propose that all the imported oil consumed can be replaced by coal, but does outline the steps necessary to develop coal-based energy alternatives which will allow progressive replacement to occur.

Natural gas also is an important fuel source in these nonutility sectors. Currently, the threat of a supply disruption of natural gas is not present. The potential for shortages does exist for several reasons. These include the uncertainty of reserve estimations; the sudden increase in demand for natural gas as a swing fuel due to a potential petroleum supply disruption; the probable increase in the fuel cost as reserves are depleted; and the possibility of import restrictions by the country of origin in order to meet their own demand.

Coal/coal-derived fuels can play an increasingly important role in the overall energy policy of the United States. Coal is not an immediate cure for an energy crisis but its use as a diversification fuel can function to mitigate the impact of an interruption or restriction of any one fuel source. The production of coal is both a capital intensive and labor intensive effort; therefore, it cannot be turned on or off at will. Identification of long-term demand and planning to meet that demand will allow coal, America's most abundant fossil fuel resource, to provide alternatives to decrease our dependence on imported energy. Conclusions and Recommendations follow.

Conclusions

Coal is our nation's most certain and predictable fossil fuel resource, yet the least used in the industrial, commercial, residential, and transportation sectors. Natural gas and electricity are the most significant forms of energy used in the industrial, commercial, and residential sectors; in the transportation sector, liquid fuel from petroleum is the predominant form of energy. Based upon these facts, the following conclusions, related to the nonutility sectors, are presented.

- **Currently, the most feasible method of penetrating the nonutility sectors is to convert coal to liquids and gas to avoid equipment and infrastructure changes. Commercial processes have been demonstrated and are in use to make coal-based liquids and gas. In the long term, new, emerging coal technologies which require infrastructure changes may have potential for use in the nonutility sectors.**

- The United States uses more oil for transportation alone each year than it produces. At the present time, only liquids or perceived liquids can play a role in the short-term replacement of gasoline and distillate. Methanol is the primary alternate liquid currently being considered for transportation. Fuel-flexible vehicles which can run on methanol, gasoline, or a mixture of the two fuels have been built and are being demonstrated in the State of California. Methanol fuel would require infrastructure changes; however, coal can be used to produce synthetic hydrocarbon liquids, which are compatible with petroleum-derived fuels and which require no infrastructure changes.

- The industrial sector offers unique opportunities for coal in the supply of chemical feedstocks and cogeneration. There are many opportunities for coal in process heat production and steam raising. Concerns have been expressed regarding the regulatory issues being inhibiting, particularly the 10 micron particulate emissions and the SO_2 and NOx control requirements.

- Coal can penetrate the commercial sector principally in two ways: district heating and cooling and cogeneration of electricity. Universities and colleges, hospitals, penitentiaries, airports, industrial/office parks, and sports and recreational complexes are some of the major commercial sector candidates for consideration.

- The application of coal in the residential sector, more than in any other sector, will be influenced by public perception. Aesthetics, convenience, and cost will be principal considerations.

- Electricity is a significant energy input into the nonutility sectors. Its use in these sectors can be thought of as an indirect use of coal because more than half of the energy supply for electricity production comes from coal. For example, in the transportation sector, electricity can be used in the electrification of railroads, regional transportation systems, and as an energy source for new, improved batteries which will be available in future mobile equipment.

- All forms of energy have environmental constraints as well as advantages. Increased penetration of coal in the nonutility sectors must be both environmentally and economically acceptable. Currently, a reasonable increase in the use of coal in the industrial and commercial sectors can be accommodated while still meeting ambient air standards. Widespread use of coal in the residential sector may pose problems in many areas. When it comes to meeting ambient air standards, all sectors need to be considered jointly to maintain compliance within a given attainment area.

- Underlying all issues in the nonutility sectors is the public perception of coal. The Work Group believes that public information is negatively presented by the media and a more balanced view is required, particularly with respect to "Acid Rain" and the "Greenhouse Effect." The importance of coal as a reliable fuel with price stability has to be emphasized as well as the fact that technologies are available to use coal in an environmentally acceptable manner. Energy education in the primary and secondary schools is needed in order to create awareness in future generations of the strategic implications of coal in the nation's energy mix.

- Paramount to all of these issues are concerns of national security and economic survival. Petroleum is currently supplying 39.6 percent of all energy used in the United States. More than 25 percent of the balance of payment deficit is currently caused by imported oil. By 1990, the country could depend on imported oil for more than 50 percent of its petroleum needs. Where will it all end?

Recommendations

To increase the use of coal in the industrial, commercial, residential, and transportation sectors, the National Coal Council recommends that the Secretary of Energy consider taking the following steps.

1. **THE TRANSPORTATION SECTOR CONSUMES 27 PERCENT OF THE TOTAL**

UNITED STATES ENERGY INPUT AND NEARLY TWO-THIRDS OF THE OIL USED IN THE COUNTRY. IT IS ALSO THE ONLY SECTOR OF THE ECONOMY ALMOST ENTIRELY DEPENDENT UPON LIQUIDS WITH LITTLE FUEL FLEXIBILITY OR DIVERSIFICATION. *THE NATIONAL COAL COUNCIL RECOMMENDS THAT THE SECRETARY COMMISSION A STUDY OF THE METHODS OF PRODUCING ALTERNATIVE TRANSPORTATION FUELS FROM COAL.* THE PURPOSE OF THE STUDY WOULD BE:

- determine which alternative fuels and direct use technologies hold the most promise, both in the short and long term, for economically converting coal into energy forms usable in the transportation sector;
- support Federal demonstration projects, in cooperation with other Federal Agencies, implementing the use of coal-derived fuels in mobile equipment; and
- define a program of demonstration projects, in cooperation with other Federal and State Agencies, for the production and use of coal-derived liquids in mobile equipment, with opportunities for industry participation and cost-sharing where appropriate.

2. ***CONTINUE TO SUPPORT PROGRAMS PROMOTING RESEARCH AND DEVELOPMENT TO CONVERT SYNGAS TO LIQUID, COAL TO GAS, AND COAL TO LIQUID IN ORDER TO LESSEN U.S. DEPENDENCE ON IMPORTED OIL.* DEMONSTRATION PROGRAMS ARE NEEDED FOR SEVERAL REASONS:**

   - to maintain a viable research and development capability as well as interest,
   - to provide the basis for expansion of coal use to avoid a national energy emergency; and
   - to provide benchmarks to measure performance and incremental costs.

3. **THE IMAGE OF COAL MUST BE REBUILT BASED UPON ITS PRESENTLY KNOWN ENVIRONMENTAL BENEFITS AND ITS POTENTIAL FOR FUTURE BENEFITS RESULTING FROM CLEAN COAL TECHNOLOGIES. TO THIS END, *THE DEPARTMENT OF ENERGY SHOULD CONVENE A WORK GROUP OF APPROPRIATE EXECUTIVE BRANCH AGENCIES/DEPARTMENTS; STATE AND LOCAL GOVERNMENT REPRESENTATIVES* (NATIONAL GOVERNORS ASSOCIATION, NATIONAL CONFERENCE OF STATE LEGISLATORS, NATIONAL LEAGUE OF CITIES); *AND INDUSTRY OFFICIALS TO DEVELOP A SUBSTANTIAL PUBLIC OUTREACH PROGRAM TO IMPROVE PERCEPTIONS AND ATTITUDES RELATED TO COAL.***

Further, the Secretary should encourage industry to become substantially more aggressive in educating and informing the public in a positive manner.

- Mount a coordinated effort under the leadership of the Department of Energy which will bring together other Federal Agencies and the energy industry to provide business and civic leaders with a more balanced view of the "Greenhouse Effect" and "Acid Rain" issues. One mechanism that could be used to accomplish this would be through the existing Interagency Task Force on the Greenhouse Effect.
- Embark upon a comprehensive program in conjunction with the Secretary of Education to expand energy awareness programs in primary and secondary schools. By creating a series of programs appropriate for each grade level, kindergarten through twelfth grade, and making these programs available nationwide and at no cost to the local school system, future generations will come to realize the essential role that energy plays in our daily lives. These programs should stress coal as the nation's most abundant fossil fuel resource.

If public information programs are not actively pursued, Congress could face pressures to enact legislation which would inhibit the future use of fossil fuels. Information currently reaching the public on these issues has been one-sided.

4. ***ENCOURAGE FEDERAL AGENCIES SUCH AS THE GENERAL SERVICES ADMINISTRATION, THE VETERANS' ADMINISTRATION, THE POSTAL SERVICE, THE DEPARTMENT OF DEFENSE, AS WELL AS THE DEPARTMENT OF ENERGY, TO INCREASE THE USE OF COAL IN PUBLIC FACILITIES.***

This action will serve as a role model or proving ground for similar applications in state and local government facilities and in commercial establishments. Since these facilities are based geographically throughout the nation, a broad-based infrastructure would be created to deliver coal/coal-derived fuel, dispose of ash and other waste, and service the equipment.

5. ***UNDERTAKE A REVIEW OF THE PERMITTING PROCESS AND THE REGULATIONS WHICH AFFECT COAL USE WITH APPROPRIATE FEDERAL AND STATE AGENCIES WITH THE OBJECTIVE OF REDUCING INCONSISTENCIES AND OVERLAPS.***

The Department of Energy should evaluate the recommendations by the Vice President's Task Force on Regulatory Relief. These recommendations provide guidance on how regulatory uncertainties can be reduced and deployment of clean coal technologies can be encouraged. Cooperative reviews of the implementation procedures of environmental regulations by Federal and state agencies could lead to accommodation of new opportunities for coal use in the industrial and commercial sectors in many attainment areas of the country.

6. ***INVESTIGATE THE USE OF ECONOMIC INCENTIVES THAT WOULD HAVE THE LARGEST IMPACT ON INCREASING THE USE OF COAL IN THE INDUSTRIAL, COMMERCIAL, RESIDENTIAL, AND TRANSPORTATION SECTORS AND SPONSOR LEGISLATION AS DEEMED APPROPRIATE.***

Incentives should be applied when appropriate for promoting the economical use of coal in an environmentally acceptable manner. Incentives also are desirable to lessen commercial risk when projects are marginally feasible.

7. ***STIMULATE INTEREST WITHIN THE COMMERCIAL SECTOR TO DEVELOP NEW COAL-FUELED DISTRICT HEATING AND COOLING SYSTEMS.***

The Department of Energy, in cooperation with the Department of Housing and Urban Development, should expand existing programs to develop model projects and to evaluate system technologies and candidates for the establishment of new coal-based energy systems on conversion to coal of existing community energy systems. The heating and cooling industry, developers, and state and local governments should be encouraged to move rapidly toward more widespread application of such systems.

8. ***REVIEW AND EVALUATE IN GREATER DETAIL THE PROGRAMS OF FOREIGN COUNTRIES WHICH HAVE SUCCESSFULLY IMPLEMENTED COAL USE IN THE INDUSTRIAL, COMMERCIAL, RESIDENTIAL, AND TRANSPORTATION SECTORS.***

The lessons learned can be applied in the appropriate sectors, taking advantage of the fact that these applications have been successful elsewhere. The study of foreign programs which use coal in the nonutility sectors should be a joint government/industry effort involving, not only the coal industry, but representatives from other affected industries.

INDUSTRIAL USE OF COAL AND CLEAN COAL TECHNOLOGY

ADDENDUM REPORT

Irving Leibson, Chairman
Coal Policy Committee

Joseph J.M. Plante
Study Group Chairman

JUNE 1990
THE NATIONAL COAL COUNCIL

Executive Summary

INDUSTRIAL SECTOR OVERVIEW

The Industrial Sector is a nonhomogeneous group, thus making it difficult to obtain uniform energy data. The approach taken in this report was to select certain of the most energy intensive industries and report on these, leaving those industries with less energy consumption unreported.

The Industrial Sector energy consumption in 1988 was 21,700 trillion Btu of which coal provided 2770 trillion Btu[1]. The last comprehensive energy survey published by the Energy Information Agency was the Manufacturing Energy Consumption Survey: Consumption of Energy, 1985[2]. Table A-1 of this survey is repeated in Appendix A for information purposes. Also included in Appendix A is Table 940 (Table A-2) from the 1989 Statistical Abstract[3] which states the 1985 data in energy equivalents of trillion Btu.

During 1988, the principal consumers of industrial coal were[4]

SIC Group		Thousand Short Tons
3312	**Coke Plants**	**41,910**
28	**Chemicals Allied Products**	**14,898**
32	**Stone Clay Glass**	**13,792**
26	**Paper and Allied Products**	**12,437**
33	**Primary Metal Industries**	**7,691**
29	**Petroleum and Coal Products**	**7,190**
20	**Food and Kindred Products**	**6,431**
37	**Transportation Equipment**	**1,836**
22	**Textile Mill Products**	**1,497**

The principal uses for coal in the Industrial Sector (in decreasing order of consumption) were[5]

Coke Plants
Steam Coal
Direct Process Heat
Manufacturing Feed Stock

The Industrial Sector is also the principal non-utility electricity producer with an installed capacity of 22,479 MW. Table A-3 in Appendix A shows a breakdown of this electric generation capacity[6]

Electricity is used extensively in industry. Electricity is over 50 percent coal based; therefore, electricity is an indirect use of coal in industry. Table A-1 in Appendix A presents energy consumption data for the manufacturing portion of the Industrial Sector.

During the years from 1973 to 1986, U.S. Industrial Production Indices increased from 94 to 125 (1977 = 100). In this same time frame, energy intensity ratios decreased from 1.0 to 0.60 (energy intensity is: Energy Consumption ÷ Federal Reserve Board Industrial Production Indices, normalized 1973 = 1.0)[7]. These values reflect a general trend of increasing energy efficiency and energy conservation in the Industrial Sector. The principal reference for the commercial and economic data is the 1989 U.S. Industrial Outlook[8].

The Industrial Sector has reacted to energy price increases with conservation and has selected fuels on the basis of economics. Some industries rely heavily on coal. For example, the cement industry uses coal for 65 percent of its fuel needs. Within the same (SIC-32) classification, the glass industry uses little or no coal. No single solution applies; each industry should be reviewed on an industry-by-industry basis. Thus, we present our conclusions, impediments, and recommendations.

CONCLUSIONS

Energy consumption per output unit of production has been declining since the 1970s as a result of energy conservation and process improvements.

The processes used by the Industrial Sector vary considerably. The use of coal and clean coal technology is application specific, even within a given SIC group code; i.e., cement and glass.

Clean coal technologies (CCTs) are primarily applicable to Industrial Boilers. Some CCTs could be adapted to direct process heat applications with further study; i.e., glass.

Natural gas is the largest source of direct process heat. This points to one of the ways in which coal ultimately can be used in the industrial sector through the application of the coal gasification technology. The long-range availability of natural gas beyond the year 2000 at reasonable prices is a subject of concern.

Industrial cogeneration is a viable way to utilize coal in the Industrial Sector. Table A-4 in Appendix A indicates that of the 31,400 MW of nonutility generation capacity, 5,400 MW are derived from coal-fired units. Many of the nonutility generators using coal are engaged in cogeneration.

The impact of currently proposed environmental legislation (i.e., acid rain, air toxics, ozone nonattainment, greenhouse) in the aggregate will cause severe industrial dislocations causing many industries to go off-shore seeking locations where more favorable environmental regulations exist. The public view may be that industrial growth will be sacrificed in favor of environmental controls. The reality is that the sacrifice will be not only *growth* but that *whole industries* will leave.

IMPEDIMENTS

The variability of different coals, both in form and chemical analysis, makes it more difficult for industrial users. A more uniform, properly sized product, deep-cleaned at the source "ready-to-use" fuel would be less difficult for the smaller industrial energy user.

The installed cost of coal handling, coal burning, and environmental controls can result in a capital cost for coal that is 2.5 to 4 times higher for coal than for natural gas. The uncertainty of new regulations further complicates the issue. Potential users of coal have the difficult task of justifying coal in the face of higher capital cost and uncertain environmental regulations.

Several industries are seasonal or have low capacity factors due to the manufacturing process. These cases usually favor lower initial capital cost.

The environmental regulatory processes at both the Federal and State levels, are viewed as a detriment to coal use in several important respects:

- emission standards are based on a percent reduction instead of relating emissions to unit of output,
- best available control technology is specified without consideration of cost justification; and
- the smaller size of units being brought under compliance requirements has made only the larger installations practical.

The public perception that coal is a dirty fuel needs to be changed. Coal can be used in an environmentally acceptable manner.

Transmission line access for independent power producers and cogenerators is difficult to arrange. There is concern about the adequacy of the electrical transmission systems in the United States as reported in the National Coal Council's June 1986 report, Interstate Transmission of Electricity.

RECOMMENDATIONS

The Department of Energy should continue to support and expand the development of technology for the conversion of coal into liquids and coal into gas.

Increase the emphasis on interagency review of the linkage between the national economy, national energy use, and the quality of life. The impact of the regulatory process with respect to cost-benefit, the impact on energy use, as well as the effect on health and welfare should be given particular attention. The results of these reviews should be widely communicated on an ongoing basis.

The Secretary of Energy should encourage research and development to evaluate the best means of using coal for direct process heat in processes such as glass manufacturing. This research and development should be undertaken with the participation of the specific industry, i.e., glass.

It is recommended that one of the clean coal technology programs be the demonstration of processes that prepare, deep-clean, and size coal (ready-to-use fuel) for industrial use.

Industry should make use of available technologies to clean, dewater, dry, and prepare coal fines rejected by the coal preparation plants. Making beneficial use of these coal wastes would reduce future waste liabilities and improve the coal industry's image.

The Secretary of Energy should take appropriate action to expedite the resolution of regulatory uncertainties and should continue active involvement in preventing future such uncertainties.

The Secretary of Energy should encourage Federal and State Governments to ensure transmission line access and power markets for independent power producers and cogenerators.

The Department of Energy should continue to support and expand the research on chemicals derived from synthesis gas from coal.

The Secretary of Energy should appoint an industry advisory committee, which should include members representing the chemical and petroleum refining industries, to advise on the research and development needs of industry with respect to increasing and upgrading the use of coal.

The Secretary of Energy should continue efforts to improve the public's awareness that there is an important role for coal and that the technology exists to burn coal in an environmentally compliant manner.

REFERENCES

1. U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook 1989: With Projections to 2000 (DOE/EIA-0383), January 1989.
2. U.S. Department of Energy, Energy Information Administration, Manufacturing Energy Consumption Survey: Consumption of Energy, 1985 (DOE/EIA-0512 - 85), 1988.
3. Statistical Abstract of the United States, 1989, 109th Edition, U.S. Department of Commerce, Bureau of the Census.
4. U.S. Department of Energy, Energy Information Administration, Quarterly Coal Report October-December 1988 (DOE/EIA-0121-88/4Q), Table 23, p.39; Table 30, p. 46.
5. U.S. Department of Energy, Energy Information Administration, Annual Outlook for US Coal, DOE/EIA-0333(89), p. 12.
6. Edison Electric Institute, 1987 Capacity and Generation of Non-Utility Sources of Energy.
7. Industrial Sector Energy Analysis: Overview of Trends in Consumption and Factors Affecting Energy Demand, American Gas Association, January 22, 1988.
8. U.S. Industrial Outlook - 1989, 30th Annual Edition, U.S. Department of Commerce/International Trade Administration, January 1989.

THE LONG-RANGE ROLE OF COAL IN THE FUTURE ENERGY STRATEGY OF THE UNITED STATES

Irving Leibson, Ph.D, Chairman
Coal Policy Committee

Donald M. Carlton, Ph.D
Work Group Chairman

The National Coal Council

June 1990

1.0

Introduction

This report was initiated on June 7, 1989 by the National Coal Council in response to a request from former Secretary of Energy John Herrington, dated November 29, 1988. In the spring of 1989, Secretary of Energy James D. Watkins reaffirmed the need for such a report to provide input to the National Energy Strategy being developed by the Department of Energy (DOE). The recommendations contained in this report are designed to help assure the proper linkage between long-range energy strategy options and coal utilization, production, and transportation.

The National Energy Strategy is designed to establish priorities and guidelines for the next 60 years that will lead to appropriate public policies and provide for rational development of energy resources and technologies. To respond to this challenge, the National Coal Council (NCC) elected to develop three plausible future scenarios, based upon a methodology developed by SRI International, (as described in Appendix C) for evaluating the potential role for coal. NCC's scenarios are diverse enough to provide for a broad range of anticipated and yet unknown factors expected over the next 60 years. The use of diverse scenarios also illustrated the need to incorporate flexibility in our nation's public policies to better respond to future uncertainties.

Each scenario describes different national and international environments, GNP growth rates, and energy growth rates. The first scenario was characterized by a reasonably coherent global, economic, and political condition over the time frame with a balanced response to economic and environmental tradeoffs in the United States, coupled with dynamic technological development.

The second scenario presented a somewhat less hospitable world. In this scenario, the global, economic, and political conditions were volatile. And, while the United States' economic and energy tradeoffs were generally balanced, only incremental technological progress was realized during this time frame.

The third scenario is set against a similarly volatile global, economic, and political condition but with a very erratic situation in the United States as competing interests force frequent and dramatic policy swings on economic and environmental issues. Coupled with only incremental progress in technology, this last scenario presents the most difficult energy climate for the world. Lastly, the Council studied a case in which the use of coal is limited to 23 quads, approximately its estimated level of consumption in about the year 2000.

A complete description of the three scenarios is contained in Appendix B. These scenarios are not predictions but rather are descriptions of plausible alternative futures. None may come to pass. Nonetheless, they can be used to guide perceptions of the future, future planning horizons, and strategic options over the 60-year time frame established for the National Energy Strategy.

The range of futures presented by the three scenarios underscored several general conclusions common to all. They are:

- Ample economic energy supplies are critical to societal stability and progress.
- Because of the large cost-competitive resource base, coal must be a major component of the nation's future energy base.

- To remain economically competitive and to preserve living standards, the United States must resolve conflicts between energy and environmental priorities in a cost-effective manner.

- Technological advances involving the utilization, production, and transportation of coal will significantly affect coal's future. Aggressive programs which develop, demonstrate, and deploy environmentally sound and cost-effective coal technologies will assure coal's position in the United States energy base.

- A political and economic climate must be fostered which provides incentives for the use of indigenous energy resources in order to limit energy imports to acceptable levels and to continue to attract investment capital for energy producers, transporters, and users.

- Single line energy forecasts for evaluating and establishing energy policies constrain the ability to respond to the ever changing political, economic, energy, and environmental challenges at home and abroad. Flexible scenario planning is essential in modelling the impacts of proposed policy changes.

- Restraining coal use at about the year 2000 level results in increased dependence on imported energy under all three scenarios. Under the 23 quad limitation case, between 30% and 60% of long term coal demand would need to be replaced by 5 to 17 MB/DOE* of additional oil and gas, unless other energy sources or forms are discovered or developed.

Specific recommendations and a discussion of these issues is contained in the body of this report. A summary of all the recommendations is presented in Section 2.0. A discussion of the challenges and opportunities confronting coal is found in Section 3.0.

Appendix A provides background information on coal production, transportation, and utilization, and expands the discussion of issues addressed in the main body of this report. The scenarios used by the National Coal Council are described in Appendix B. Appendix C contains excerpts of scenarios developed with the assistance of SRI International. The National Coal Council used these scenarios as a guide in developing the scenarios used in preparing this report.

Appendix D contains correspondence between the National Coal Council and the Secretary of Energy. Twenty letters commenting on various drafts of this report can be found in Appendix E. Appendix F is a copy of the minority report. A description of the National Coal Council, a list of the members of the Council and the Coal Policy Committee, and a list of the members of the Long-Range Role of Coal Work Group are located in Appendices G, H, and I, respectively.

*Million barrels per day oil equivalent.

2.0

Executive Summary, Findings, and Recommendations

Based on a wide range of reasonable assumptions about growth in the United States population, state of the economy, concerns for the environment, and improvements in the efficiency of energy use, it is evident that the United States must continue to rely heavily on its vast coal resources. In fact, the United States is fortunate that it can rely on this resource to meet its energy demand rather than depending upon less reliable foreign energy sources. This conclusion follows logically from all major energy forecast models currently in use by government and the private sector, as well as the scenarios developed for this report.

While energy costs declined in real terms during the 1980's for various reasons, during the next 10 years the converse will occur: real energy prices will increase because of inadequate domestic supplies (except for coal) and the cost of complying with environmental and other regulations. Thus the challenges facing energy policy makers will be to ensure adequate energy supplies at reasonable prices which in turn will require that balanced energy policies prevail over the strategic time period.

Coal is our nation's largest indigenous resource of fossil fuel, constituting almost 95% of the nation's proved fossil energy resources.[1] On an energy equivalent basis, demonstrated coal reserves in the United States are 43 percent greater than the world's combined known oil and natural gas reserves.[2] Additionally, America's coal reserves account for 35 percent of the world's proved recoverable coal.[3] As Figure 2 (Appendix A, page 3) illustrates, coal is the only energy resource which alone can meet United States consumption over the next 60-year period. For these reasons, coal is a strategic energy resource of importance to every citizen of the United States.

Coal is not only a vital national energy resource, but also a key component of the economies of the 26 states in which it is mined, providing over 140,000 direct mining and coal preparation jobs as well as an estimated 20,000 indirect jobs in management, sales, and related activities. According to the "Inventory of Power Plants in the United States, 1988," nine states rely on coal-fired power for 75% or more of their electric generation. An additional 14 states rely upon coal for between 50% to 70% of their electric generation, while another 5 states rely on coal for over 40% of their electric generation.[4]

Over the last decade, coal producers achieved sustained competitive progress, registering steady increases in output (from 824 MM tons per year in 1981 to 975 MM tons per year in 1989). Coal productivity (tons per-employee hour) also increased 85% over this time period.[5] This has resulted in a real reduction in consumer coal prices, without sacrificing the industry's commitment to reduce environmental impacts and improve health and safety. Over this period of time, the coal industry has evolved from a primarily labor-intensive industry to one which is highly automated using computer age technology.

Since 1973, the consumption of coal by the electric utility sector increased by 96% while total sulfur dioxide emissions from this same sector fell 22%. At present approximately 57% of electricity generated is produced from coal. In general terms this equates to an annual off-set of 556.2 million barrels of oil or 3.1 trillion standard cubic feet of natural gas. During the 1980's, coal once again proved itself an essential, dependable, versatile, and competitive domestic energy resource.

The Long-Range Role of Coal in the Future Energy Strategy of the United States

Today coal accounts for 25% of total United States energy consumption.[6] Generation of electricity is coal's largest market, accounting for 78% of all coal demand and 85% of United States consumption.[7] The principal factor in establishing full confidence in the ability of the United States to rely on its vast coal resources into the next century centers on meeting the environmental challenges--principally sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) emissions that are allegedly linked to acid precipitation.

Technologies now exist, and more effective technologies are being developed, that significantly curtail the releases of SO_2 and NO_x from coal combustion. While carbon dioxide (CO_2) emissions have been speculatively linked to global warming (global warming is not a demonstrated or verifiable phenomenon and remains a source of significant controversy in the scientific community). CO_2 emission rates per kilowatt can be reduced through increased efficiency in the combustion of fossil fuels. It should be noted, however, that the elimination of all United States coal-fired power plants would only reduce annual global CO_2 emissions by an estimated 3 percent.

Many of these facts are well understood by those concerned with energy, environmental, and economic matters, but are poorly comprehended by the public, and as such pose a significant challenge to coal. In fact today's coal industry is so poorly understood that the challenges already met and surpassed in production, environmental protection, and health and safety over the last two decades are virtually unknown outside the coal industry and the aforementioned expert communities. The National Coal Council has repeatedly cited the need for improvement in the public's perception of coal and the industries it supports. It is vital that the public be made aware of the facts regarding coal use in the 1990s and beyond, rather than allow an outdated image of coal to hinder future progress in energy use.

Coal has been viewed as a resource which someone must produce, someone else must transport, and a third party must use. There has been little demand either for an integrated examination of the entire industry or for an integrated response to the challeges it faces. As outlined in this report, now is the time for such an integrated response because these challenges to the coal industry affect all segments of society. In an uncertain energy future, America's biggest asset is its vast coal reserves which represent the best alternative for meeting increased energy needs at reasonable costs while maintaining and improving environmental quality.

Coal's ability to play a major role in the long-range energy strategy of the United States is influenced by numerous existing and potential road blocks. The National Coal Council has described such impediments and road blocks in each of its previously issued reports as follows:

- *Improving International Competitiveness of U.S. Coal and Coal Technologies*, pages 1-6
- *Clean Coal Technology*, Chapter 2, pages 21-27
- *Innovative Clean Coal Technology Deployment*, Chapter 2, pages 17-21
- *Interstate Transmission of Electricity*, Chapter 4
- *Coal Conversion*, Chapter 3
- *Reserve Data Base*, pages 1,2,11-21,77-96,101-104
- *The Use of Coal in the Industrial, Commercial, Residential, and Transportation Sectors*, Chapter 6
- *Report on Industrial Boiler New Sources Performance Standards*, Chapter 6.

The United States relies upon the mechanism of a free market, and internationally, both East and West are moving toward market-based economies. As it has done in the past, coal must compete in these markets. Within this context, the National Coal Council Report and the following recommendations focus on the linkage between energy use over the next 60 years, and the role economically competitive coal-based technology can play.

RECOMMENDATIONS

THE SECRETARY OF ENERGY SHOULD ENSURE THAT THE NATIONAL ENERGY STRATEGY ACKNOWLEDGES THE IMPORTANCE OF COAL IN THE NATION'S ENERGY AND ECONOMIC FUTURE.

Coal must be a cornerstone of the National Energy Strategy. America's coal reserves constitute almost 95% of proved native fossil fuel energy reserves. For this reason alone, coal is a strategic economic and energy resource. Coal occurs in 38 of the 50 states and is mined in 26, constituting a recoverable resource approaching 268 billion tons. Twenty-three states rely upon coal for 50% or more of the electricity generated within their borders. Additionally, over 5,000 mining and preparation companies across the country provide over 140,000 direct and over 20,000 indirect jobs. The abundance and diversity of coal enables it to meet a variety of energy and industrial needs at competitive and stable prices.

At present, 57% of the electricity produced in the United States is generated from coal, accounting for 85% of domestic coal consumption. Coal can produce even larger amounts of electricity and could, over time, be available to the public in other forms, such as liquids and gases, which would extend its contribution. There could be substantial benefits to the United States from increased domestic coal use in place of some energy imports. Among those benefits are new jobs, industrial growth, improved trade balance, and enhanced energy security.

The National Energy Strategy should provide enough stability for coal use in the United States to preserve the efficient recovery of coal from the nation's reserves, and to preserve and attract investment in the coal industry. In this regard, the Secretary of Energy should exercise leadership in creating the positive political, regulatory, and economic climate necessary for the continued expansion of coal use in this country. The periodic calls by elected officials and others for the unilateral curtailment of coal use in this country lead to uncertainty about coal and its importance to the nation, and must be countered by the Department of Energy through effective public information programs.

(Additional information is provided on pages: 10, 11, 12, 15, 16, 17, 18, 19, 20, 21, 24, 25, 26, 38, 43, 44, 45)

THE SECRETARY OF ENERGY SHOULD EXPEDITE THE COMPLETION AND DEPLOYMENT OF SELECTED CLEAN COAL TECHNOLOGY (CCT) PROJECTS, AND IN THE FUTURE SHOULD DIRECT THE PROGRAM TOWARD NEW TECHNOLOGIES WHICH PROMISE TO YIELD HIGHER ENERGY CONVERSION EFFICIENCIES AND LOWER ENVIRONMENTAL IMPACTS.

The key to the full utilization of the vast United States coal resource base is technology. Without economically competitive clean coal technologies, coal will be an underutilized resource. With such technologies, it provides a domestic source of ample energy needed for the nation to meet its economic, political, and societal goals for many years to come. Thus, the support for CCT within the Department of Energy is an important indicator of this government's recognition of coal's essential importance to domestic and international energy markets. These programs should be expedited and mechanisms found to make deployment of CCT processes more attractive in the near term. Among the mechanisms the Secretary should employ are: (1) establish legal precedent to allow for modernization of existing electric generation capacity and industrial steam boilers such that new source performance standards are not immediately triggered; (2) encourage reliance upon indigenous energy resources to limit energy imports to acceptable levels; (3) encourage public utility commissions to evaluate fuel economics over the expected life of electric generating facilities; and (4) minimize disincentives to the use of clean coal technologies imposed by future Clean Air Act requirements.

In the worldwide market, coal will compete with other fossil fuel sources to meet the needs not only of this nation, but also of other nations. Where coal is a fuel of choice, the great resources of the United States will become more valuable. For this reason, and because energy costs play such a significant role in the United States economy, it is vital to the national interest to continue a vigorous program to improve the economics and environmental acceptability of coal.

The development of clean coal technology must include cleaning and beneficiation technologies. Cleaning coal reduces its cost as a fuel because environmental impacts are mitigated, and transportation costs and undesirable use features, such as slagging and fouling, are lessened. Similarly, this program must include mechanisms and techniques for increasing the availability of existing electric generation facilities, to produce more electricity in the near term without major capital requirements.

(Additional information is provided on pages: 10, 11, 12, 13, 14, 15, 28, 29, 45, 46)

THE SECRETARY OF ENERGY SHOULD EXERT LEADERSHIP IN THE FORMULATION OF NATIONAL AND INTERNATIONAL SCIENTIFIC STUDIES WHICH LEAD TO BETTER UNDERSTANDING OF ENVIRONMENTAL ISSUES RELATING TO ENERGY USE.

The Department of Energy must be actively involved in the International Panel on Climate Change (IPCC) and other national and international bodies concerned with global environmental issues to assure that sufficient scientific justification is available for any environmental initiative that affects the national energy policy. Current scientific evidence is contradictory regarding global climatic changes. Action by the United States to limit specific emissions, such as carbon dioxide, would severely impact the nation's economy and national security. The Secretary must take the lead in assuring that global environmental issues are fully explored and that any proposed actions are based upon facts and supported by consensus in the worldwide community of scientists. Any actions considered or taken must be fully justified on an economic basis, and dealt with equally by all nations.

(Additional information is provided on pages: 11, 12, 13, 43, 44)

THE SECRETARY OF ENERGY SHOULD ENSURE THAT THE NATIONAL ENERGY STRATEGY CALLS FOR NATIONAL AND INTERNATIONAL POLICIES WHICH FOSTER IMPROVED ENERGY EFFICIENCIES.

Leaders here and abroad should be encouraged and supported in their efforts to foster and promote energy efficiency improvements. Specifically, lesser-developed countries (LDC) should be supported in the efficient development and use of their indigenous energy resources. The government of the United States should encourage lesser-developed countries to import United States-developed, energy-efficient technologies which reduce environmental impacts and improve the prospects for economic expansion in these nations. It is estimated that Pacific Rim nations alone will install 49,000 megawatts of new electric generation capacity in this decade. These investments will define long-term commitments to coal or alternative fuels over the bulk of the time period considered for this strategy. Thus, decisions made in the next 10 years will affect coal and coal technology export opportunities for many years to come.

(Additional information is provided on pages: 11, 14, 16, 17, 27, 28, 38, 43, 44)

THE SECRETARY OF ENERGY SHOULD DEVELOP A PROGRAM BY WHICH THE ECONOMIC RISKS ASSOCIATED WITH LARGE-SCALE FACILITIES BASED ON COAL CAN BE MITIGATED SO THAT COMMERCIAL DEPLOYMENT OF CLEAN COAL-BASED TECHNOLOGIES CAN TAKE PLACE.

Current coal production and utilization of approximately one billion tons per year is testimony to coal's importance. New technologies will permit coal's contribution to be extended and its current position to be reinforced. The Secretary of Energy is therefore encouraged to seek mechanisms, such as tax credits, accelerated capital depreciation, "first-of-a-kind" risk protection relative to costs imposed by accelerated environmental compliance schedules etc., by which the risks of commercial deployment can be made more acceptable. This will allow newly-developed technologies to be available when required.

Unlike imported energy, the cost of coal is driven primarily by production costs. These costs have come down as productivity improvements have increased (85% since 1978). Thus, domestic energy, particularly coal, offers the greatest resistance to energy cost fluctuations (increases) caused by international political and economic forces beyond our control. This will be the case so long as environmental and other regulatory constraints are reasonable and predictable. This is a powerful advantage the nation can ill afford to ignore.

The Secretary must work closely with other members of the Cabinet and Congress, and state and local governments, including utility commissions, to assure that short-term policy decisions do not preclude long-term investment in coal-based industrial and electric generation facilities. It is particularly important that the Secretary or his designee(s) appear before and bring to these bodies the potential impact and importance of their decisions to the National Energy Strategy.

(Additional information is provided on pages: 11, 12, 13, 14, 15, 18, 44, 45)

THE SECRETARY OF ENERGY SHOULD ENSURE THAT THE NATIONAL ENERGY STRATEGY PROMOTES THE DEVELOPMENT AND DEMONSTRATION OF TECHNOLOGIES FOR PRODUCING COAL-DERIVED LIQUIDS AND GASES.

Technologies have rendered coal the most versatile of fossil fuels. Technologies to convert coal to liquids and gases must be at the core of the nation's energy strategy in order to (1) cap the upper limits on imported oil and gas prices, and (2) create the potential to increase domestic supplies of liquid and gaseous fuels as much as may be necessary to meet national demand, and protect economic and national security.

Deployment of technologies for producing coal-derived liquids and gases is also likely to put an upper limit on the cost levels of imported energy, and should reduce the impact of foreign energy supply fluctuation and price increases.

(Additional information is provided on pages: 11, 12, 14, 15, 16, 44)

THE SECRETARY OF ENERGY SHOULD ENSURE THAT THE NATIONAL ENERGY STRATEGY FACILITATES THE EFFICIENT UTILIZATION OF THE EXISTING COAL TRANSPORTATION INFRASTRUCTURE, AND RECOMMENDS FEDERAL EMINENT DOMAIN POWERS TO SECURE ADEQUATE RIGHTS-OF-WAY FOR THE TRANSPORT OF COAL OVER THE TIME PERIOD EXAMINED IN THIS REPORT. ADDITIONALLY, THE STRATEGY SHOULD SUPPORT THE IMPLEMENTATION OF THE RECOMMENDATIONS OF THE "INTERSTATE TRANSMISSION OF ELECTRICITY" REPORT OF THE NATIONAL COAL COUNCIL DATED JUNE 1986.

Mechanisms to resolve rights-of-way issues in a timely manner will enhance the efficient development of domestic coal resources and the deployment of innovative transport technologies such as coal slurry pipelines. Additionally, coordination of the Department of Energy's efforts to develop a National Energy Strategy with the current efforts of the Department of Transportation to develop a National Transportation Strategy will further assure that the needs of each sector are addressed completely and efficiently. Lastly, DOE should work with state public utility commissions to assure adequate and proper distribution of electricity within and among states. In particular, the Department of Energy must work to ensure that electric utilities are able to develop the transmission networks necessary to efficiently move power from the most economic sources.

(Additional information is provided on pages: 15, 29, 30, 31, 32, 33, 34, 35, 36)

THE SECRETARY OF ENERGY SHOULD ASSURE THE DEVELOPMENT AND DEPLOYMENT OF A COMPREHENSIVE WORLDWIDE ENERGY FORECAST MODELING CAPABILITY.

It is essential that the National Energy Strategy be flexible and reflect a variety of scenarios for energy use, environmental impact and economic growth. To do this, improved modeling capabilities must be available so that future uncertainties can be addressed efficiently and in a timely manner. The Secretary of Energy must develop and deploy such modeling capability to enhance the ability to respond to the ever changing political, economic, energy, and environmental challenges at home and abroad.

The scenarios which the National Coal Council developed for this report, and those developed with the assistance of SRI International, address economic growth, energy supply, and environmental issues. The National Coal Council does not have the resources or modeling capability required to rigorously evaluate the assumptions included in the scenarios. Nevertheless, the scenarios provide an example of an excellent mechanism for establishing an objective means for evaluating trade-offs among these issues, and illustrate the urgent need for an examination of these trade-offs before major public policy initiatives in energy are embarked upon.

(Additional information is provided on pages: 1, 2, 3, 12, 13, 43, 46, Appendix C)

THE SECRETARY OF ENERGY SHOULD WORK WITH THE SECRETARIES OF THE INTERIOR AND LABOR, AND THE ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY TO: SEEK BALANCED, ECONOMIC SOLUTIONS TO FUTURE MINING-RELATED ENVIRONMENTAL ISSUES AND MORE FLEXIBILITY IN BRINGING INNOVATIVE SOLUTIONS FOR MINE SAFETY TO THE WORK PLACE; ASSURE TIMELY AVAILABILITY OF FEDERALLY-CONTROLLED COAL RESERVES TO PRIVATE ENTERPRISE; AND PROMOTE FUTURE MINING TECHNOLOGY DEVELOPMENT

In the last 10 years, the United States coal industry has made substantial progress in regaining a competitive position in the United States and world energy markets by increasing productivity 85% while simultaneously improving its environmental and safety record. This achievement is the result of the industry's response to record growth in coal demand and heightened competition among coal producers seeking to maximize their share of the market growth. Consumers see these changes in the form of utility coal prices that have declined 28% in real terms during the last 10 years.

These changes are the result of new approaches to management, labor relations, mine safety, and the use of new technologies within the coal industry. The industry is proud of its achievements and is predicting increased coal production to 1 billion tons by 1991. The coal industry recognizes that future environmental and safety concerns will need to be addressed by both government and industry. However, to efficiently progress to the billion ton level and beyond, the coal mining industry must strive for balanced solutions that achieve the desired environmental and safety results while improving the economic competitiveness of the industry. DOE can play a valuable role as an advocate for the United States coal mining industry, by working with the Departments of the Interior and Labor, and the Environmental Protection Agency to achieve balanced solutions that permit further growth of U.S. coal production.

(Additional information is provided on pages: 4, 10, 11, 12, 17, 37, 38, 39, 40, 41)

[1] U.S. Crude Oil and Natural Gas and Natural Gas Liquid Resources Annual Report 1988, EIA-0216, Table 1, p. 3.

[2] Facts About Coal-1989, National Coal Association, p. 5.

[3] Ibid.

[4] Ibid, p. 36.

[5] Ibid, p. 24.

[6] Ibid, p. 35.

[7] EIA Report 1988.

ENCLOSURE NUMBER TWO

The National Coal Council
Recommendations
To The Secretaries of Energy
Pertaining to Clean Coal Technology

June 1986 - June 1990

The National Coal Council

Recommendations to the Secretaries of Energy Pertaining to Clean Coal Technology

Report Title	Date	Recommendation
Clean Coal Technology	June 1986	1. The establishment of an effective coordination mechanism between federal and state programs that will ensure that funding is applied to programs in as broad, but effective, a manner as possible with commitments to multiyear programs. The establishment of this coordination mechanism could be initiated by the Secretary of Energy calling for a conference of governors from coal utilizing and coal producing states along with the heads of affected federal agencies. Because the Department of Energy is administering the largest source of funds for technology development, it should take a leadership role in this coordinated effort. 2. Legislation may be needed in the individual states to generate a portion of the funding required for clean coal technology demonstrations. Furthermore, the electric utilities need to be provided with the pass-through of demonstration costs into the electricity rate base by the state Public Utility Commissions. This needs to include the allowance of returns on capital investment commensurate with participant's risk for the facilities required for demonstration and commercialization of the clean coal technologies, as well as retrofits from oil or gas to coal use. 3. Out of the conference proposed above, a panel of industry executives needs to be established under the Secretary of Energy that is empowered to provide a combined business and technical judgment, guidance, and direction for the Department of Energy's Fossil Energy Budget (including the various clean coal technology programs). We believe such a panel could provide valuable input to the Department of Energy in prioritization of research efforts in areas of strong commercial promise. 4. The development of an effective demonstration program consisting of appropriately-sized projects to ensure technology acceptance in each area highlighted as most promising is needed.

Report Title	Date	Recommendations
Clean Coal Technology (cont.)	June 1986	5. More stringent emission standards should not be applied without regard for the development and demonstration of appropriate clean coal technologies to allow for cost-effective compliance. 6. The Secretary should use his office to aid in developing a consistent national energy policy which recognizes the role clean coal use must play in maintaining our future economic growth while ensuring a greater level of energy self-sufficiency and security. The Secretary must then insulate the programs used to develop clean coal technologies from arbitrary changes in directions and funding. 7. Appropriately-sized demonstration plants are vital to successful implementation of clean coal technologies. The Federal government, along with state governments, needs to take an active role in sharing the financial and technical risks of bringing clean coal use technologies to commercial fruition. Financial grants by government on a cost sharing basis with industry are likely to produce the most successful and timely projects. 8. With future strictures expected on DOE budgets because of the Gramm-Rudman legislation and other deficit reduction programs, innovative methods need to be found to pick up the shortfall in funding available for developing clean coal technologies. The Secretary should take the initiative in exploring the possibility of establishing development consortia which include DOE, the governments of the coal producing states, and major coal users and producers. 9. The Secretary should work to convince public utility regulatory agencies that the cost of clean coal use technology research, development, and demonstration will ultimately benefit not only the nation but the utility customers as well. As such, the cost and risk of developing clean coal technologies is a cost of doing business and these costs must be recoverable from the rate payer. 10. The Secretary should recommend to the

Report Title	Date	Recommendations
Clean Coal Technology (Cont.)	June 1986	Congress and the EPA that the emission standards should be revised so that they define only control levels which are linked to health and welfare requirements. The selection of the method of control used to meet these requirements should be left to the coal user.
Coal Conversion	June 1986	1. The Secretary of Energy should establish demonstration projects in identified technology areas with emphasis on establishing fuel switching capabilities (oil/gas/coal) as widely as possible. 2. The Secretary of Energy should establish a national clearinghouse for the exchange and dissemination of technical information resulting from technology demonstration projects and from other industrial and electric utility coal conversion projects. 3. The present exemption for Prevention of Significant Deterioration permitting and from New Source Performance Standards for coal converting facilities should be retained within the Clean Air Act and its regulatory framework. Specifically, the Department of Energy definition of "coal capable" under the Powerplant and Industrial Fuel Use Act should be retained and adopted by the Environmental Protection Agency (EPA). 4. The Department of Energy should position itself to deal with the question of whether coal-derived liquids (other than coal-derived gasoline or diesel fuel) and alternate fuel-burning vehicles meet the EPA emission standards. 5. The federal government can provide increased market support for coal-derived fuels (other than coal-derived gasoline or diesel fuel) by expanding its coal-derived liquid fuel program for government vehicle fleets. 6. The Secretary of Energy should retain and expand programs which move toward development of the clean coal technology necessary for coal to penetrate this market.

Report Title	Date	Recommendations
Report on Industrial Boiler New Source Performance Standards	June 1986	**1. The Secretary of Energy should ensure that NSPS regulations for new technologies be based upon careful studies of actual commercial units in the applicable size ranges. This is consistent with recommendations made in the NCC report entitled, "Clean Coal Technology."**
Improving International Competitiveness of U.S. Coal and Coal Technologies	June 1987	1. Further funding by the U.S. government and private industry of research and development efforts for clean coal technologies will contribute to increased competitiveness of U.S. coal exports.
Innovative Clean Coal Technology Deployment	November 1988	1. Complete the ongoing DOE-cosponsored Innovative Clean Coal Technology (ICCT) demonstration initiative as planned. 2. Clearly define the scope and extent of ICCT "deployment." 3. Actively encourage, at the state level, utility and industrial participation in ICCT deployment efforts by allowing or providing: --Full construction work in progress (CWIP) in rate base, and/or accelerated depreciation, both of which allow a company to recover capital investment more quickly. --Incentive rate of return to recognize that riskier plants--like demonstrations of new technologies--may require higher return to compensate for higher risks. This should consider risk adjustments to the authorized rates of return for utilities deploying ICCTs. --Preconstruction assurance that expenditures will be considered prudent within a phased prudency review mechanism that establishes agreed-upon expenditure caps for each corresponding phase of the project. --Appropriate expense treatment for contributions to collaborative industry efforts and R&D costs, including equipment used solely for R&D purposes. --Regulatory modifications to allow ICCT to

Report Title	Date	Recommendations
Innovative Clean Coal Technology Deployment (cont.)	November 1988	receive treatment now only accorded existing cogeneration and renewable energy sources. This could include, for example, investment tax credits for the necessary equipment. Such modifications should also encourage and expedite ICCT deployment by industrial and other nonutility coal users, recognizing that these companies can be a valuable source of technology, funding, and commercial leadership. 4. Ensure that air quality legislation places priority on sustaining the remarkable national progress made over the past 15 years in emission reduction with the least impact on cost and productivity by providing: --Sufficient compliance time for ICCT deployment so the market can confidently choose the least-cost solutions from among an array of emission control options. An effective strategy should be designed to ensure the availability of the necessary options to the market, not to artificially restrict that market. --Maximum practical freedom of choice among alternatives for meeting defined emission control objectives without biases in favor of specific "equipment" solutions. Such biases have proven to both inhibit technology development and increase compliance cost. --Encouragement of risk management-based environmental policies that enhance energy competitiveness as well as environmental protection. Such policies provide a valuable cost/benefit framework for achieving public understanding and consensus. --The resources necessary to confidently measure the energy balance of the earth as the essential foundation for understanding the greenhouse effect and any related energy policy implications. 5. Lower Federal and State environmental regulatory barriers to wider use of ICCT options by providing: --Flexible source emission reduction targets,

Report Title	Date	Recommendations
Innovative Clean Coal Technology Deployment (Cont.)	November 1988	which would include "bubbling" to reduce costs by allowing averaging of emission over all facilities in a state or region, and tradable emission permit system, provided that ambient air standards are maintained. --Tonnage reduction compliance standards, allowing utilities to receive full credit for gross emission reductions achieved by demand-reducing strategies. --Expanded Innovative Control Technology waiver provisions in the Clean Air Act, and revise requirements so that waivers may extend beyond four years after startup. --Interstate air quality management coordination to encourage neighboring states to implement cooperative strategies for emissions reductions, including emissions trading among states. This should consider compensation to the entities responsible for establishing the tradable environmental margins. 6. Modify federal, state, and local environmental permitting procedures to expedite and encourage ICCT deployment, and provide a permitting reference for consistent and uniform application of federal regulations. Key points to be addressed include the following: --"Grandfather" ICCT installations from further emission reductions for a period of time which recognizes the investment made in the installation. Such safe harboring provisions should be linked, for example, to the depreciation period of the installation. --Revise Environmental Protection Agency (EPA) regulations to prevent voluntary modifications from triggering even tighter controls at plants which already have an emissions reduction program. --Allow existing sources currently in compliance with regulations to apply for innovative technology waivers in order to improve cost and integrated environmental control performance.

Report Title	Date	Recommendations
Innovative Clean Coal Technology Deployment (Cont.)	November 1988	--Develop a uniform federal and state permitting procedure for technologies which promise to reduce emissions at lower cost. 7. Conduct an ICCT public education and consensus-building campaign. 8. Provide, where appropriate, federal and state economic incentives to accelerate ICCT deployment without distorting the energy market. 9. Remove restrictions on collaborative technology development and demonstration investments by commercial competitors. 10. Establish a bipartisan coal and related technology export policy coordinating council under the auspices of Congress and the President. 11. Review and modify applicable federal law, as appropriate, to permit the U.S. coal industry to form trading companies for the export of coal and coal technologies.
The Use of Coal in the Industrial, Commercial, Residential and Transportation Sectors	December 1988	1. The transportation sector consumes 27 percent of the total United States energy input and nearly two-thirds of the oil used in the country. It is also the only sector of the economy almost entirely dependent on liquids with little fuel flexibility or diversification. The Secretary should commission a study of the methods of producing alternative transportation fuels from coal. The purpose of the study would be: --determine which alternative fuels and direct use technologies hold the most promise, both in the short and long term, for economically converting coal into energy forms usable in the transportation sector; --support federal demonstration projects, in cooperation with other Federal Agencies, implementing the use of coal-derived fuels in mobile equipment; and

Report Title	Date	Recommendations
The Use of Coal in the Industrial, Commercial, Residential and Transportation Sectors (Cont.)	December 1988	--define a program of demonstration projects, in cooperation with other Federal and State Agencies, for the production and use of coal-derived liquids in mobile equipment, with opportunities for industry participation and cost-sharing where appropriate. 2. Continue to support programs promoting research and development to convert syngas to liquid, coal to gas, and coal to liquid in order to lessen U.S. dependence on imported oil. Demonstration programs are needed for several reasons: --to maintain a viable research and development capability as well as interest; --to provide the basis for expansion of coal use to avoid a national energy emergency; and --to provide benchmarks to measure performance and incremental costs.
Industrial Use of Coal and Clean Coal Technology--Addendum Report	June 1990	1. The Department of Energy should continue to support and expand the development of technology for the conversion of coal into liquids and coal into gas. 2. The Secretary of Energy should encourage research and development to evaluate the best means of using coal for direct process heat in processes such as glass manufacturing. This research and development should be undertaken with the participation of the specific industry, i.e., glass. 3. It is recommended that one of the clean coal technology programs be the demonstrations of processes that prepare, deep-clean, and size coal (ready-to-use fuel) for industrial use. 4. Industry should make use of available technologies to clean, dewater, dry, and prepare coal fines rejected by the coal preparation plants. Making beneficial use of these coal wastes would reduce future waste liabilities and improve the coal industry's image. 5. The Department of Energy should continue

Report Title	Date	Recommendations
Industrial Use of Coal and Clean Coal Technology--Addendum Report (Cont.)	June 1990	to support and expand the research on chemicals derived from synthesis gas from coal. 6. The Secretary of Energy should appoint an industry advisory committee, which should include members representing the chemical and petroleum refining industries, to advise on the research and development needs of industry with respect to increasing and upgrading the use of coal.
The Long-Range Role of Coal in the Future Energy Strategy of the United States	June 1990	1. The Secretary of Energy should expedite the completion and deployment of selected clean coal technology (CCT) projects, and in the future should direct the program toward new technologies which promise to yield higher energy conversion efficiencies and lower environmental impacts. 2. The Secretary of Energy should ensure that the National Energy Strategy promotes the development and demonstration of technologies for producing coal-derived liquids and gases.

QUESTIONS FOR THE RECORD
HEARINGS ON S. 341
THE NATIONAL ENERGY SECURITY ACT OF 1991
MARCH 19, 1991
JACK E. KATLIC, CHAIRMAN
NATIONAL COAL ASSOCIATION

1. What are the regulatory impediments to development and deployment of clean coal technologies?

As identified in the National Coal Council report, Innovative Clean Coal Technology Deployment, November 1988, there are four basic reasons that commercialization of clean coal technologies will be difficult. These reasons include the technical risks associated with deploying a new and relatively unproven technology; commercial risks resulting from uncertain energy, trade and regulatory policies and market conditions; environmental policy risks which may change at any time, and; regulatory uncertainties that expose investors to unexpected, after the fact risks.

Regulatory impediments to deployment of clean coal technologies are at federal, state and local levels. Over the past decade, the regulatory environment for utilities has become very complex due to rising costs, increased competition in the electric power industry, uncertain prospects for demand growth and need for new capacity. The regulatory process has become much less predictable and utilities have become much more concerned about the risks of not recovering the costs associated with new investments.

The length of time and difficulty of obtaining approval of projects, state prudency reviews, and rate regulations combine to discourage a utility from taking the risk of investing in a new technology that may not be successful, may be more costly or less efficient that expected.

2. What can the Congress do to address these regulatory impediments?

There are several types of regulatory reforms and incentives that could reduce the risks associated with CCT development and deployment. These include: rolling prudency reviews, incentive rates of return on CCT investments; reduction of regulatory lags; simplified siting and project approval procedures; exemption from NSPS requirements and tax incentives. The Congress could adopt the incentives for deployment of Clean Coal Technologies that were included in the original Clean Air Act Amendments as proposed by the Bush Administration in 1989. These include:

- a requirement that FERC establish incentive rates of return for clean coal technology;

- a requirement that FERC establish a process by which developers of technologies may negotiate with FERC to agree upon cost caps for future projects and to obtain preapproval of the prudency of expenses for projects if the expenses fall within the agreed upon cap.

- Congressional encouragement to states to adopt rate incentives and pre prudency review of clean coal projects. These incentives should include but not be limited to:

  1) preapproval of recovery of capital costs and other expenses within reasonable bounds agreed upon before project construction;

  2) elimination of retroactive "used and useful" reviews for CCTs;

  3) rapid amortization of clean coal technology expenditures; and

  4) immediate recovery of a portion of clean coal technology expenses through a fuel adjustment clause or by some other method.

3. What incentives are necessary for commercialization of clean coal technologies?

In addition to the incentives outlined under question two, federal tax incentives would enhance the probability for commercialization of clean coal technologies. While a number of tax related incentives may be appropriate, we would like to focus on the following:

1. enactment of a tax credit for investment in qualifying clean coal technology, and

2. classification of clean coal technology property as qualifying for 5 year cost recovery treatment.

Both would be consistent with the way that the NES proposes to treat certain renewable energy technologies.

4. Mr. Gentile testified that the provisions of S. 341 are generally consistent with DOE's current programs, the NES, and the FY-92 budget request. Do you agree with that?

The provisions of S. 341 are more comprehensive than those included in DOE's current programs, the NES and the FY-92 budget. S. 341 would establish a research, development and demonstration program for advanced coal technologies; would develop an RD&D plan for non-fuel uses of coal; would look at the potential for coal fuel mixtures and establish an RD&D program to utilize coal-water slurries in diesel locomotive engines. NCA supports all these programs to develop new technologies as consistent with the goal of reducing imports of energy (oil) by better utilizing domestic resources - including coal - while balancing economic and environmental requirements.

The NES recommendations with respect to coal RD&D are broadly consistent with the provisions of S.341 in that a goal of the NES is to "promote development and demonstration of new coal-related technologies". The NES further states that on of the "major efforts in the coal sector is to continue implementing the Clean Coal Technology Program." Unfortunately, words and actions do not seem to be consistent.

The program suggested in Sec. 5001, S. 341, goes beyond the current clean coal program and is not at this point being funded by DOE. A review of the FY 1992 budget shows that the other programs proposed in S. 341 are not now being funded by the Department.

Delaying Round V of the Clean Coal Technology Program is not consistent with the emphasis placed on the importance of this program in the NES. Strong private sector interest has been present for the first three solicitations. We expect the strong base of interest to continue through the May 17, 1991 Round IV solicitations and into Round V.

A significant increase in power generation capacity is projected to be needed early in the next century. These projections seem to be universal whether made by DOE (both in the NES and the Annual Energy Outlook) or by other forecasters. The Clean Coal Program will demonstrate the commercial viability of a number of more advance technologies for power generation from coal. Commercial scale demonstrations of the technologies is a multi year project. Delaying Round V could seriously impede timely achievement of this critical programs objectives.

5. There are a number of innovative coal refining technologies emerging that may have great potential for producing clean-burning fuels and by-products feedstocks.

a) Should we be putting more federal money into these technologies?
b) What do you believe the potential is for these technologies?

The coal refinery concept is not new. Direct or indirect liquefaction and mild gasification technologies produce liquids and by-products that can be used for a number of purposes, most specifically to replace petroleum and petroleum products in the transportation market as well as in markets traditionally served with products that are the result of refining crude petroleum.

a) Continued demonstration and commercialization of these technologies depend heavily on a stable (and sufficiently high) price of oil. As the probability that this condition will be met is relatively small, demonstration and commercialization will most likely depend upon additional federal dollars. A program could be devised in which the risks and costs of development are shared between industry and government - much like the clean coal program that is presently being funded by Congress and administered by the DOE.

According to data included in DOE's FY 1991 budget, dollars appropriated for "coal refining technologies" total $41.8 million. Additionally, two clean coal projects, the ENCOAL project in Wyoming and the Ohio Clean Fuels project in Ohio (CCT - I) involve technologies that are essentially refining coal.

It appears from a review of the FY 1992 budget however, that the funding requests for coal refining technology (outside the CCT program) have been reduced considerably. In view of the potential that these technologies have to replace dependence on foreign energy sources, NCA questions the wisdom of reducing the funds spent for this research. We would recommend that DOE devote MORE, not LESS dollars, on coal refinery technologies.

b) The potential for these technologies seems to be unlimited. Once they are successfully demonstrated on a commercial scale, these technologies should allow coal derived products to compete with petroleum in all of its many uses from transportation to chemicals to use in existing oil fired turbines.

Both fuel and non-fuel markets are significant for the products of mild gasification technologies. The non fuel market includes form coke, electrodes, carbon black, activated carbon and coal derived liquids. Direct liquefaction produces a distillate hydrocarbon liquid that can serve as a direct substitute for imported oil for the production of hydrocarbon transportation fuels and heating oils. Indirect liquefaction can produce hydrocarbon transportation fuels as will as alcohol and/or ethers for use in cleaner burning transportation fuel markets.

6. You recommend in your testimony that we include in legislation a program for development of coal-derived liquid and gaseous transportation fuels.

a) How adequate are DOE's current programs?

b) What size of program would you recommend?

c) How is DOE's work in this area related to the work done by the Office of Conservation and Renewable Energy in alternative fuels?

a) An acceleration of the program to develop the coal refinery concept would, in essence, be a program for the development of coal-derived liquid and gaseous transportation fuels. As pointed out in the answer to question five, the current funding for these programs seem to be on the low side and, if the proposed FY 1992 budget were to be passed as proposed, would be lower still during the next fiscal year. Without an increase in funding (or alternatively a guaranteed oil price floor sufficiently high to make projects economic on their own right), it is not likely that the technologies will make further advances in a timely manner.

b) We would recommend that a program be developed to support commercial scale deployment of at least two, but preferably more, projects each with a different technology. We would also recommend that the costs of the program be shared between industry and government. An analysis of the most promising technologies should be completed to determine the costs of constructing two (or more) plants and these dollars should be included in the next Fiscal Year budget.

Market based incentives are equally as important. The Clean Air Act of 1990 provides a market incentive for alternative transportation fuels as does the President's announced program to convert a percentage of the federal fleet to alternative fuels. Extension of these programs beyond governments to the private sector would provide the basis for further commercialization of these technologies.

c) National Coal Association understands that the alternate fuels work done by the Office of Conservation and Renewable Energy is focused on alcohol fuels produced from biomass. This R&D effort does not include coal or other fossil fuels.

J. BENNETT JOHNSTON, LOUISIANA, CHAIRMAN
DALE BUMPERS, ARKANSAS
WENDELL H. FORD, KENTUCKY
BILL BRADLEY, NEW JERSEY
JEFF BINGAMAN, NEW MEXICO
TIMOTHY E. WIRTH, COLORADO
KENT CONRAD, NORTH DAKOTA
DANIEL K. AKAKA, HAWAII
WYCHE FOWLER, JR., GEORGIA
RICHARD C. SHELBY, ALABAMA
PAUL WELLSTONE, MINNESOTA
MALCOLM WALLOP, WYOMING
MARK O. HATFIELD, OREGON
PETE V. DOMENICI, NEW MEXICO
FRANK H. MURKOWSKI, ALASKA
DON NICKLES, OKLAHOMA
CONRAD BURNS, MONTANA
LARRY E. CRAIG, IDAHO
JOHN SEYMOUR, CALIFORNIA
JAKE GARN, UTAH
BENJAMIN S. COOPER, STAFF DIRECTOR
D. MICHAEL HARVEY, CHIEF COUNSEL
C. ROBERT WALLACE, STAFF DIRECTOR FOR THE MINORITY
GARY G. ELLSWORTH, CHIEF COUNSEL FOR THE MINORITY

United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150

March 20, 1991

Kurt E. Yeager
Senior Vice President
Technical Operations
Electric Power Research Institute
P.O. Box 10412
Palo Alto, California 94303

Dear Mr. ~~Yeager:~~ Kurt

I want to thank you for your testimony yesterday before the Subcommittee on Energy Research and Development on the coal provisions of S.341, the National Energy Security Act of 1991.

As a follow-up to that hearing, I am enclosing questions to be provided for the printed hearing record. I am requesting that the answers to these questions be provided to the Subcommittee no later than March 29, 1991.

Thank you again, and I look forward to working with you in the future.

Sincerely,

Wendell

Wendell H. Ford
Chairman, Subcommittee on
Energy Research and Development

Followup Questions for Kurt Yeager

From Senator Ford

1. What are the regulatory impediments to development and deployment of clean coal technologies?

2. What can the Congress do to address these regulatory impediments?

3. What incentives are necessary for commercialization?

4. Mr. Gentile testified that the provisions of S.341 are generally consistent with DOE's current programs, the NES, and the FY-92 budget request. Do you agree with that?

5. There are a number of innovative coal refining technologies emerging that may have great potential for producing clean-burning fuels and by-product feedstocks.

a. Should we be putting more federal money into these technologies?

b. What do you believe the potential is for these technologies?

6. You state in your testimoy that the Administration's National Energy Strategy will result in the use of 40 percent more oil by 2030. I find that very discouraging. How did you come up with that analysis?

7. In your testimony, you talk about the various technical objectives that need to be met for clean coal technology.

a. Can these technical objectives still be met if federal funding is reduced?
b. What will be the impact of the failure to do so?

8. You talk about the economic impact of focusing environmental compliance on control requirements rather than on pollution prevention. You say that the U.S. now spends $80 billion per year to meet these requirements. I assume that you are talking about private sector spending.

How do we change that emphasis, so that more of our money is put into developing new technologies that will address the problem in the beginning rather than the end?

EPRI
Electric Power
Research Institute

April 15, 1991

Senator Wendell H. Ford
Chairman, Subcommittee on
Energy Research and Development
United States Senate
Washington, D.C. 20510-6150

Dear Senator Ford:

The following is provided in response to the questions you posed in your March 20 letter, following-up my testimony before the Subcommittee concerning opportunities for clean coal technology. Thank you for your patience and I appreciate your confidence by inviting me into the deliberations of the Subcommittee. Please contact me at any time if I or my colleagues at EPRI can be of further assistance.

Questions 1, 2 & 3

Because they are closely interconnected, I have taken the liberty of providing integrated responses to the first three questions.

What are the regulatory impediments to development and deployment of clean coal technologies and what can the Congress do to address these impediments? What incentives are necessary for commercialization?

- Complete the ongoing DOE cosponsored Clean Coal Technology demonstration initiative. In order to achieve the greatest national benefit, the initiative should preferentially encourage technologies such as coal refining that emphasize increased energy efficiency and productivity, as well as emission reduction. The most promising technologies should be demonstrated over the range of designs, coals, and operating variables necessary to confidently map the commercial application envelope of each.

- Remove restrictions on collaborative technology development and demonstration investments by commercial competitors. This recognizes that in a global market, the ability to maintain the nation's industrial base depends on pooling public and private investment to share the risks of technology commercialization. Failure to do so will

Headquarters 3412 Hillview Avenue, Post Office Box 10412, Palo Alto, CA 94303 USA • (415) 855-2000 • Telex 82977 EPRI UF • Telecopy (415) 855-2954
Washington Office 1019 Nineteenth Street, NW, Suite 1000, Washington, DC 20036, USA • (202) 872-9222 • Telecopy (202) 296-5436

result in the ultimate "restraint of trade", i.e.; an unproductive industrial base without marketable assets.

- Actively encourage electric utility clean coal technology deployment at the state level by (a) allowing full construction work in progress (CWIP) in the rate base, (b) providing incentive rates of return for new clean coal technology to compensate for higher risks, (c) assuring appropriate expense treatment for contributions to collaborative industry R&D efforts, including necessary equipment, (d) preconstruction assurance that expenditures on clean coal technology installations will be considered prudent within a phased prudency review mechanism that establishes caps for each corresponding phase of the project.
- Modify federal, state and local environmental permitting procedures to expedite and encourage clean coal technology deployment. This should include uniform federal and state permitting procedures for technologies that promise to reduce emissions at lower cost. Other key points to be addressed should be the ability to "grandfather" clean coal technology installations for a period of time that recognizes the investment made in the installation, and revision of EPA regulations to prevent voluntary technology modifications from triggering even tighter controls on plants in compliance.
- Provide federal and state economic incentives to accelerate clean coal technology development and deployment. This could include investment tax credits, accelerated depreciation, and increases in existing caps on tax-free industrial development bonds.
- Review and modify applicable federal law to permit U.S. industry to form trading companies for the export of coal technology. These trading companies should have access to Export-Import Bank financing, the ability to finance clean coal-related construction projects in foreign countries, and be empowered to engage in banking transactions to accommodate variations in exchange rates.

Question 4

My greatest disagreement with Mr. Gentile's analysis would be the FY-92 DOE budget request. In its current form, it is not consistent with either S.341 on, in my judgement, the NES. Not only does the budget request eliminate Round 5 of the Clean Coal Technology demonstration initiative but it seems to divert those funds already appropriated by Congress to the general fossil R&D budget. The net result is about a 35% reduction in the coal R&D budget, which would have been 75% without the diversion. In a more general sense, I believe both S.341 and the NES understate the role coal can, and should, play to reduce oil imports on behalf of U.S. energy security and economic competitiveness. This is a national opportunity that neither Japan and Europe, our primary economic competition, can match.

Question 5

(a) I would certainly invest more federal, and private sector, money on a joint venture basis into innovative coal refining technologies based primarily on coal gasification to assure their confident commercial deployment this decade.

(b) I would do so because I believe these technologies have the greatest potential to: (1) improve the efficiency and productivity of coal use, (2) meet increasingly stringent emission control requirements, including CO_2, (3) reduce our growing dependence on imported oil by converting coal to synthetic petroleum products, (4) cleanly co-process waste products to energy, including municipal refuse, sewage sludge and biomass, (5) utilize U.S. developed technology to provide the world class power plant best meeting the energy and environmental requirements of the coming decades, (6) restore U.S. technological and competitive business leadership in a world that must increasingly depend on coal.

The economic threshold today for these refining technologies based on coal gasification is natural gas delivered at about $4.00/MBtu and oil at about $30/bbl (1990 $). It is probable that these conditions will exist by, if not before, the end of this decade. It is therefore prudent, independent of environmental requirements, that we accelerate our deployment of these technologies based on economic competitiveness and national security.

Question 6

My testimony indicated that the Administration's NES will result in the use of 40% more imported oil by 2030. This is derived from Figure C-21 on Appendix page C-22 of the February 1991 NES document. This indeed is very discouraging and is one important reason why I encourage increased emphasis on coal refining to produce not only clean electricity but synthetic petroleum to more aggressively reduce our dangerous dependence on oil imports.

Question 7

The primary role of federal funding is to accelerate the achievement of the various technical objectives for clean coal technology by sharing the risks inherent in the development and deployment of new technology. Failure to provide these federal/private risk sharing joint ventures will therefore delay the objectives, in my judgement, by at least 10 years. The implications of this delay are several: (a) U.S. technical and commercial leadership will be lost allowing foreign sources to capitalize on U.S. coal research initiatives, not only in the global energy market but our domestic market as well. (b) Our ability to meet existing and anticipated environmental regulations with coal technology that can improve, rather than depress, productivity will be delayed thus further reducing U.S. competitiveness. (c) We will delay our ability to reduce dependence on imported oil with resulting erosion of our balance of trade and national energy security. What the ultimate risk of this delay will be in human and economic terms is difficult to quantify but it certainly dwarfs the relatively modest level of federal risk-sharing required to assure that we are able to use our abundant domestic resources to stay out of harm's way.

Question 8

Yes, my response to the $80 billion/yr for environmental compliance refers to private sector spending. This annual expense is expected to more than double as a result of the recent Clean Air Act Amendments. Regrettable, they will maintain the unproductive emphasis on after the fact, "end of pipe", cleanup with only about 1% spent on technology capable of improving efficiency and productivity, together with environmental protection.

I believe we can change this emphasis by developing the national understanding and will to do so. This should: (a) recognize that environmental protection must ultimately rest on a sound economic base. Without a productive, competitive economy we will lose the resources and the will to protect the environment, (b) rely on objective scientific and technological assessments, such as the NAPAP effort commissioned by Congress, as the basis for environmental legislation and regulation, (c) recognize that the solutions to our interconnected energy and environmental issues will require a sustained, holistic, strategy which balances all risks, (d) reject politically expedient crisis management and after-the-fact cleanup, as counterproductive to achieving sustainable solutions for our environmental challenges that are becoming increasingly global in scope, (e) understand that efficiency in the use of resources, and the innovative technologies which achieve that efficiency, are the key to sustainable development of all our resources, including the environment, (f) emphasize public education and leadership to achieve a knowledgeable national consensus on energy security and the environment that matches our historic consensus on military security. Such a campaign must recognize and overcome the adversarial conditions that have inhibited a workable consensus on coal, for example. This will require credible involvement by all public and private stakeholders.

Very truly yours,

Kurt E. Yeager
Senior Vice President
Technical Operations

KEY.9885.L/bd

hi
HAGUE INTERNATIONAL
3 ADAMS STREET
SOUTH PORTLAND, MAINE 04106

207-799-7346

1991 APR -2 AM 3 36

March 29, 1991

The Honorable Wendell H. Ford
Chairman Subcommittee on Energy Research & Development
Washington, D.C. 20510-6150

Dear Mr. Ford:

The following comments are submitted in response to your letter of March 20, 1991, regarding the EFCC Project, pursuant to the testimony of Paul G. LaHaye on S. 341 on March 19, 1991.

A) "What will the demonstration show?"

Initial data will be obtained on the life expectancy under operating conditions of a ceramic gas turbine air heater when exposed to the products of coal combustion at elevated temperatures (2200 to 2650°F). This data will include:

a) Leakage rate of the air heater at gas turbine operating pressures, which will affect the cycle thermal conversion efficiency.

b) Effectiveness of the "self-cleaning" slag screen in preventing ash deposit build-up on the air heater tubes.

c) Basic data on the performance of the air heater, i.e. overall effectiveness (how well does it transfer heat, how big, etc.).

d) Operating characteristics and performance of an air-cooled coal combustor suitable for use with the ceramic air heater.

Also, based on the data performance described above and using available gas and steam turbines, as well as other standard commercial hardware, the performance of the EFCC cycle for electric utility application will be more accurately predicted. A comparison will be made of the EFCC to other competitive emerging technologies.

In summary, the work through this FY91 at Portland, Maine, will provide a preliminary technical assessment of the coal-fired air heater components for use with a gas turbine. In the next fiscal year at Kennebunk, Maine, an assessment of the viability of the coal-fired air heater for the EFCC cycle will be conducted.

To obtain data that will permit a reasonably accurate prediction of life expectancy, the air heater would require at least 2,000 hours of operating experience. Only 300 hours of air heater operation are contemplated under the presently funded program at Kennebunk. We are currently arranging for an additional 2,000 hours with Florida Power Corporation. Florida Power has suggested that such a test under utility supervision will be necessary for the electric utility to accept the concept. This operation at Florida Power would probably begin in fiscal year 1993, assuming funding is available. The test would be conducted on a coal-fired utility boiler in Florida Power's system.

B) "What is the next step?"

In order to complete testing at Kennebunk other EFCC subsystems should be added to the test facility. In 1992, assuming success with the tests in 1991, a gas turbine and a stack gas clean-up system would be added to the air heater. This would permit an assessment of other subsystems in the EFCC, such as:

a) the arrangement of controls.

b) the steam and water injection ahead of the ceramic air heater and the gas turbine to further improve cycle performance.

c) a new stack gas clean-up system in the process of development at Union Carbide Chemical. This new process is called the "Cansolv" Process. It has been shown to remove 98% of SO_2 from stack gas (based on early results obtained with an operating prototype in Canada). We would add such a unit to the Kennebunk facility to prove the concept on the indirect-fired gas turbine. This would also provide additional operating experience on the air heater, the air-cooled combustor and the self-cleaning slag screen.

In parallel with the work at Kennebunk, DuPont has initiated work on a prototype plant rated 7MW. This project is in the initial phases of definition at this writing and will be submitted to Department of Energy (DOE-METC) in May. The cycle is based on an Allison gas turbine and our gas turbine air heater. If approved by DuPont and METC, detailed design would begin in November of this year and the DuPont project should be ready to go to hardware in fiscal year 1993. This would occur immediately after we complete the preliminary air heater, coal-fired tests in Kennebunk, and before we initiate life test at Florida Power Corporation.

As you know, the program is on a test track and has been getting good support from DOE-METC.

C) "How far away is your technology form commercialization, both in terms of year and dollars?"

The following summarizes our current plans:

Identify & Rating	Probable Location	Prime Responsibility	Year In Service	Total Cost MM (Dollars)	Govt. Share MM (Dollars)
1) Kennebunk "Air Heater Test"	Kennebunk, ME in Progress	Hague Int.	1991/92	6.5	5.0
2) Kennebunk Air Heater & Gas Turbine w/ Union Carbide Scrubber	Kennebunk, ME in Progress	Hague Int.	1992/93	5.5	4.4
3) Utility Life Test	St. Petersburg, Florida	Florida Power	1993	5.5	3.6
4) Prototype 7MW	Waynesboro, VA	DuPont	1993/94	44.0	28.0
5) Demo #1 100MW 100 MW Utility	Florida Alt #1 Maine Alt #2 Penn.	Members of EFCC Consortium	1997	135.0	67.5
6) Demo #2 50 MW Industrial	Northeast	Members of EFCC Consortium	1997	70.0	35.0
		Estimated Cost (1991 dollars)		266.5	143.5
		Contingency		66.6	35.9
		Total Est (1991)		333.1	179.4

It would seem reasonable at this juncture to expect this technology to be available for general use during the period from 1998 to 2000, and the total government cost to be in the order of 200 MM dollars (1991).

D) "Should more federal money be invested in this technology?"

We are a 30-person organization and so far we are the largest cash and in-kind contributor next to the government. METC has been very cooperative in relieving the financial burden on this organization, but they have limits on what they can do. Our principal problem is that we are acting as bankers for the Consortium members in order to meet the critical deadlines in the project. Surprisingly, we get a lot of "the checks in the mail" promises from very large "blue chip" organizations. Commercial bankers do not exist for an organization like ours, resulting in a cash flow that is frequently tight.

Unsolicited statement and question.

Federal government departments, such as the Department of Energy or Department of Commerce, due to their size and structure have developed operating philosophies that closely parallel that of other large organizations such as General Motors, General Electric Company and other multi-nationals, as should be expected. There are of course exceptions within such government departments. These exceptions usually occur in "outposts" such as METC, where the director, if a strong leader, will impose some of his own philosophies on the organization at the "outpost". In general, however, government departments emulate other large bureaucracies.

Numerous small, independent organizations, are one of the strengths of the United States. Small organizations consisting of a few to several hundred individuals are uniquely American. All agree that such organizations are of benefit to the country and should be nurtured. Unfortunately, despite "Set Asides", the Small Business Administration and other attempts to favor small organizations put in place by the Congress, there remains an underlying discomfort on the part of government administrators when dealing with small businesses. These administrators have much to lose and nothing to gain by dealing with small business. A General Motor's Director can not personally take the money and run to South America, but the principal in a small organization can easily do so. Yet, most small organizations are more productive by a factor of two or more, compared to our large corporations. The great majority of small research and development organizations are as ethical, and possibly more so, than are large corporations in the United States. It is my belief that it is in our national interest to encourage the formation of more small independents and that they should be nurtured by government agencies.

E) "What can be done by the Congress to encourage this?"

1) Create a Federal Bank to work with small business - independent

of the "horse thieves" that run commercial banks in the country today.

2) Stop forcing small business to abide by certain of the financing rules which were originally set up for large corporations doing business with the government. First example: "In-kind", contributions are more difficult to provide from a small business base than is the case for a profitable large corporation, and yet small businesses are expected to make the same contributions. Second example: when a small business submits an unsolicited proposal, it is not entitled to add a fee for their services, whereas, if the submittal is in response to a government request for the proposal, a fee is acceptable. This does not encourage unsolicited proposals that are more apt to be submitted by a small business.

3) Contract cancellations and modifications are more difficult to accommodate in a small business than they are in a large corporation, because in a small organization the government contract is more frequently a relatively larger portion of the organization's activities. The government responsibility for contract changes or modifications should be expanded in proportion to the importance of the work to the organization, i.e. a share of the company's annual sales.

4) Fees should be added on or increased when a contract is finished within budget and on time - fees can be used to encourage excellence.

We have many similar suggestions and I hope you will forgive us for taking advantage of your request for information on the EFCC Project in this way.

Yours sincerely,

Paul

Paul G. LaHaye

cc: Senator G. Mitchell
Senator W. Cohen
Representative O. Snowe
Representative T. Andrews

PGL/bjt

Appendix II—Additional Material Submitted for the Record

WILLIAMS TECHNOLOGIES, INC.
320 SOUTH BOSTON, SUITE 831
TULSA, OKLAHOMA 74103
(918) 582-5811

March 21, 1991

The Honorable Malcolm Wallop
Senate Committee on Energy and Natural Resources
312 Dirksen Senate Office Building
Washington, DC 20510

Dear Senator Wallop:

As Chairman of the Coal & Slurry Technology Association and Executive Vice President of Williams Technologies, Inc., the operator of the Black Mesa Pipeline, I commend you on the introduction of S. 341, the "National Energy Security Act of 1991". I was disappointed, however, that S. 341 did not provide for the federal right of eminent domain for coal pipelines. On behalf of the CSTA Board of Directors, we respectfully urge that you and Chairman J. Bennett Johnston include such a provision as an amendment to S. 341.

Senator Wallop, you have been a supporter of coal pipeline legislation in the Senate for many years; and you, in particular, were responsible for the artfully crafted water language which protects western water rights. Since Wyoming is the largest domestic coal producing state, I hope you will agree how important enactment of coal pipeline legislation is at this time.

At the hearing of March 19th on Subtitle A of Title V of S. 341 before the Subcommittee on Energy Research and Development, two of the distinguished witnesses, William Carr, Chairman of the National Coal Council, and Jack Catlec, Chairman of the National Coal Association, testified enthusiastically in support of coal slurry pipelines. Further, Senator Conrad Burns questioned Secretary Robert Gentile as to why coal pipeline legislation was not included in S. 570, the Administration's energy bill, since support for this legislation was prominently covered in the Administration's National Energy Strategy (NES). Secretary Gentile's response was that he "expected it to be a Congressional initiative". Senator Wallop, that is exactly why a coal pipeline provision is so critical to S. 341, your National Energy Security Bill. Only then can we build on the Administration's support which was reflected in the NES. As you and your colleagues well noted at the hearing, all of the coal provisions of the NES were conspicuously deleted from S. 570, the Administration's bill.

Senator Wallop, we have just concluded a war in the Persian Gulf that emphasizes an unhealthy dependence on foreign oil. Clearly, we have enough coal in this country to satisfy our energy needs for some 400 years. To properly utilize this great natural resource, though, we need economical transportation options like coal pipelines. Compliance with the Clean

Air Act will require utilities to burn substantially greater amounts of low-sulfur coal. Many believe the railroads will capitalize on this by increasing their rates dramatically on these longer hauls. In short, with passage of the Clean Air Act Amendments, the economical transportation of coal by pipeline is more critical today than in past years.

The Coal & Slurry Technology Association is particularly interested in Section 5005 of Title V of S. 341, in which you require the Secretary of Energy to prepare a report on technologies for combining coal with other materials, such as oil or water. In order for these environmentally sound, coal-water mixtures to be fully commercialized, we must be able to transport them through pipelines. By 2010, the U.S. hopes to curb oil imports 40%-45% and reduce oil use by 3.4 million barrels a day. By burning coal-water fuels in power plants and industrial boilers that now burn fuel oil derived from imported petroleum, it is estimated that oil imports would be reduced by 1 to 1-1/2 million barrels a day.

Senator Wallop, we respectfully request that you put coal pipeline eminent domain language into your legislation. This will reflect the support which the Administration gave to coal pipelines in its National Energy Strategy. The coal slurry industry is willing to abide by your stringent state water law protections, but we must remove the artificial legal barriers which block the potential construction of coal pipelines.

Sincerely,

H. J. Brolick
Executive Vice President

/dc

ASSOCIATION
OF AMERICAN
RAILROADS

William H. Dempsey
President

April 10, 1991

The Honorable J. Bennett Johnston
Chairman, Committee on Energy and
  Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

The Association of American Railroads (AAR), whose members transport more than 90 percent of the Nation's rail freight, has previously submitted comments for the record on S. 341, the National Energy Security Act of 1991. Those comments were limited to an explanation of the railroad industry's opposition to § 5008 of S. 341, which would require the Department of Energy to perform a study of rail coal rates. The railroads remain opposed to § 5008 and ask that it be deleted for the reasons stated in those earlier comments (a copy of which is attached to this statement).

AAR also desires to file a separate statement for the record on transportation energy issues generally. Accordingly, AAR requests that these comments be incorporated into the record of this Committee's consideration of S. 341.

Among the Congressional findings and purposes of S. 341 are the goals of reducing oil consumption and enhancing the role of coal in meeting the Nation's energy needs. Additional purposes of S. 341 are to encourage more efficient use of energy throughout the economy and to reduce the consumption of oil in the transportation sector in particular. The Nation's railroads assist in the fulfillment of these findings and purposes more effectively than any other mode of transportation. Not only are the railroads the predominant transporter of coal but the railroads are also the most efficient transportation mode in terms of energy use. Congress, and members of the Senate Committee on Energy and Natural Resources in particular, should formally acknowledge the unique role that the railroads play in fulfilling the Congressional findings and purposes of S. 341, both in terms of energy transporter and energy user.

RAILROADS AS ENERGY TRANSPORTERS

Coal is an important element of the Nation's energy needs, and the railroads are an equally important element of the

Nation's coal delivery needs. Coal constitutes 23 percent of domestic energy use. Unlike petroleum, the United States does not depend on foreign sources for its coal supplies. Domestic coal production has increased from 781 million tons in 1979 to 980 million tons in 1989. Of this tonnage, over 60 percent is transported by railroad. In 1989, coal transportation represented 39 percent of rail tonnage, 22 percent of rail freight revenues, and 27 percent of rail carloadings.

Moreover, the railroads are better equipped now than in the past to increase coal tonnage significantly. As a result of the reforms brought about by the Staggers Rail Act of 1980, rail roadway and structures are in far better condition now than ten years ago and the industry is in a far better financial position to make new investment in roadway and equipment as necessary. Significant unused capacity in the railroad industry currently exists for the transportation of coal (and other commodities). For example, over the past four years, there has been an average daily surplus of approximately 9500 open-top hopper cars and gondola cars available for coal transportation. The railroads are capable of increasing the quantity of coal transported over the rails to meet the Nation's energy needs.

Not only are the railroads the principal means of transporting coal, but their costs of doing so are less today than they were in the early 1980's. Since enactment of the Staggers Act, railroad ton-miles per employee have increased by 122 percent, revenue ton-miles per mile of road have improved 57 percent, revenue ton-miles per freight car have climbed 56 percent, while operating expenses (in real dollars) per ton-mile have declined by 41 percent.

As a result of these efficiencies, coal shippers paid railroads an average of 2.16 cents per ton-mile in 1989, slightly less than the 2.18 cents they paid in 1980. When adjusted for inflation, rail coal rates have actually declined by 19.8 percent between 1982 and 1989. In fact, coal rates generate the second lowest revenue per ton-mile of any major commodity.

In addition to the efficiencies realized as a result of Staggers Act reform, railroad operations exhibit particular economies as traffic density increases. All other things being equal, as traffic volume increases, unit costs go down. For example, according to one economic study, a 10 percent increase in rail traffic volume would cause a two percent decrease in average transportation costs. As more and more coal is transported over the Nation's rails, those costs will continue to decline.

RAILROADS AS ENERGY USERS

Railroads have a natural energy efficiency and are far more efficient in energy consumption than trucks. The low gradients of railroad track and the low friction of steel wheels on steel rails provide an inherent efficiency that results in low energy consumption. Compared to trucks, railroads consume about one-third as much energy per ton-mile of freight carried. If a 10 percent shift in long-haul freight from truck to rail occurred, it would produce a savings of approximately 240 million gallons of diesel fuel per year.

Railroads are not content to rest on their inherent fuel efficiency. They have improved their fuel efficiency by more than 40 percent over the last ten years. In 1979 the railroads transported 225 revenue ton-miles per gallon of fuel consumed. By 1989 that figure increased to 320 revenue ton-miles per gallon. The railroads continue to engage in research to gain further increases in fuel efficiency. These efforts include new freight car designs using lighter weight materials, new engine designs, and advanced train control systems which use computers to control the dispatching and speed of trains. In addition, railroads produce far less pollution than trucks per ton of freight moved. So, any shift of traffic from truck to rail will reduce both oil consumption and air pollution. The national energy policy should recognize the energy and environmental savings inherent in railroad transportation of freight.

The national energy policy as set forth in S. 341 should seek to make maximum use of the railroad industry's role in the efficient transportation of our Nation's coal reserves as a secure energy alternative to imported petroleum.

Sincerely,

W. H. Dempsey

Attachment

cc: Committee Members

William H. Dempsey
President

ASSOCIATION
OF AMERICAN
RAILROADS

March 18, 1991

The Honorable Wendell H. Ford
Chairman, Subcommittee on Energy Research
    and Development
Committee on Energy and Natural Resources
United States Senate
Washington, DC   20510

Dear Mr. Chairman:

On behalf of our member railroads, which collectively move more than 90 percent of the nation's rail freight, I request that the following comments on S. 341 be inserted into the hearing record.

The freight railroad industry is strongly opposed to Section 5008 of S. 341. Section 5008 requires the Department of Energy (DOE) to monitor railroad coal rates. It would require DOE to study rail coal rates from January 1, 1988 through December 31, 1997, and to submit interim reports to Congress in 1993, 1995, and 1998. Ostensibly, the purpose is to determine if reregulation of the railroads is necessary.

Section 5008 would have DOE monitor rail coal-rate increases occurring as a result of the Clean Air Act Amendments of 1990 and "other Federal policies," plus monitor increases or decreases in the revenue to variable cost ratios of coal transportation rates, and any electric rate increases that might be attributable to higher coal transportation costs.

For more than 100 years, Congress has charged the Interstate Commerce Commission (ICC) with such functions. In fact, the ICC continues to monitor rail coal rates. Railroad coal rates were not completely deregulated by the Staggers Act. No other agency in government has either the knowledge or expertise to perform such a function.

However, our objection to Section 5008 extends well beyond the fact that DOE is an inappropriate agency to monitor railroad coal rates. Such additional economic scrutiny of the railroads is

50 F Street, N.W., Washington, D.C. 20001 (202) 639-2402

unnecessary, it will be counter-productive to the intent of Congress to reduce and eliminate needless economic regulation, it unjustly singles out railroads for special new regulatory burdens, and it will impose substantial new costs on railroads and the federal government.

When Congress passed the Staggers Rail Act of 1980, it made a finding of fact that failure of the railroad industry to achieve increased earnings would result in either further deterioration of the rail system or the necessity for additional federal subsidy. Congress determined that demand and competition were to be the principal regulators, and that regulation of maximum rates -- by the ICC -- was to continue only where an absence of effective competition exists. This has been the policy of the ICC since passage of the Staggers Act, and it has worked for the benefit of coal shippers, the railroads and the public.

More than a decade of experience under railroad deregulation is available for study -- and the results prove overwhelmingly that the Staggers Act is accomplishing precisely what Congress intended in 1980. Railroads have achieved, on a daily basis, freedoms from governmental interference and enhanced abilities to price their services according to market forces.

These freedoms allowed railroads to survive a long and deep recession of the early 1980s, a shift in the U.S. economy from basic production, a downsizing of many manufactured products, substitution of lighter materials for heavy ones, unabated foreign competition for U.S. export markets, a growing domestic reliance on imports, and the unparalleled competitive pressures ensuing from trucking deregulation.

Although the railroad industry remains demonstrably revenue inadequate, the financial malaise that characterized the industry during the 1970s has been removed. Instead of an industry distinguished by a high rate of bankruptcies, deferred maintenance, service deficiencies and rising accident rates, today's rail freight carriers have been investing at record levels in new plant and equipment, have been winning back traffic from the highways due to superior rate and service offerings, and have improved their safety record substantially. Clearly, coal shippers and the public have been a major beneficiary of the Staggers Act.

Railroad rate increases -- especially those on coal -- have been so modest as to have trailed inflation consistently since the Staggers Act was passed. According to a study by economists at the Federal Trade Commission, annual consumer savings from partial rail deregulation -- lower rates, more timely and more reliable service -- have topped $15 billion. The U.S. Department of Justice reported that rail service improvements came from efficiency gains and were not accompanied by an increase in rail rates.

Further, the U.S. General Accounting Office has reported: "Rail service has improved for many shippers, and railroads generally are more responsive to shippers' needs." The GAO cited contract ratemaking as "one of the most significant benefits" of the Staggers Act through which "shippers receive reduced rates and improved service in return for volume commitments," allowing them to "better plan their operations and investments and thus enhance their competitiveness." Some 60 percent of total rail traffic now moves under contract, including 86 percent of coal traffic.

Indeed, coal shippers have been especially fortunate under rail deregulation. Since passage of the Staggers Act, rail coal rates -- when adjusted for inflation --declined by more than 10 percent. For a commodity that places an inordinate burden on railroads -- almost 40 percent of tonnage -- coal's contribution to railroad revenues is only 22 percent.

Much of the increased investment in plant and equipment over the past decade has been for the benefit of coal, which often is moved in 10,000-ton unit trains that place severe stress upon track and track structure in much the same manner as heavy trucks create severe stress on pavements. Over the past 10 years, railroads have invested more than $30 billion in new plant and equipment, plus spent in excess of $100 billion on maintenance. Tens of millions of research dollars have been directed specifically at means of hauling heavy loads such as coal more productively.

The efficiency improvements of railroads, combined with the moderation in rate increases, is why not a single piece of legislation was introduced in the 101st Congress to amend the Staggers Act. In fact, only one coal-rate complaint was filed with the ICC in 1989, only one complaint in 1990, and none at all so far in 1991.

Clearly, there is no demonstrated need for saddling the railroads with additional economic regulation or regulatory burdens. Such regulation would be expensive -- both to the railroads and to the government. This is because, as stated, 86 percent of coal moves under contract -- at negotiated rates whose terms, by law, are confidential. In order for a government agency to perform the detailed analysis required by Section 5008, either that confidentiality would have to be ignored (which coal shippers, as much as railroads, would oppose), or special new reporting requirements and confidentiality safeguards would have to be adopted. Further, Section 5008 is very similar to a provision rejected last year by the House.

One of the fundamental causes of rail financial difficulties during the 20th century has been unique treatment of the railroads. For example, railroads continue to be singled out for special treatment in the areas of injured-employee liability (the Federal Employers' Liability Act, or FELA) and labor relations (secondary boycotts).

Section 5008 is another attempt at such unique treatment. Not only is no other mode so singled out, but neither is the transportation of any other energy source. Such unique treatment of railroads also is rejected by the Administration's national energy strategy, which recommends the repeal of FELA and a prohibition of secondary boycotts against railroads and airlines as exists under the Taft-Hartley Act for all other industries. The committee should not exacerbate the inequities to which railroads are subject by allowing Section 5008 to remain in the bill.

Rather than treating railroads as an impediment to national energy policy, Congress should recognize railroads as a complement to that policy. Railroads transport freight in the most fuel efficient and environmentally safe manner of any of the surface modes. Government studies show railroads to be three times more energy efficient than their principal competitor, heavy trucking; and when upstream return of barges is considered, railroads also are more fuel efficient than their inland waterways competitors.

In fact, according to the President's national energy strategy, railroads use just 2 percent of petroleum consumed by all transportation modes. And because railroads consume so much less fuel than their competitors, they are environmentally preferable. According to a recent study performed for the Environmental Protection Agency, railroads hauled three times the ton-miles of trucks but emitted just a fraction of the hydro-carbons, carbon-monoxide, nitrogen oxide and particulate matter as motor carriers.

Finally, railroads offer a solution to congested and deteriorating highways. According to the Federal Railroad Administration, railroads could handle four times their current volume of freight with minimal expansion (and all of that expansion financed through the private sector).

Although the AAR will file a separate statement for the record to cover other energy issues, it should be recognized that a current motor carrier proposal to increase the length and weight of trucks on our highways would have a further debilitating effect on those highways, the rail industry, and shippers who depend on railroads for essential transportation services.

Some trucking interests are arguing for massive increases in truck sizes and weights: the legalization, nationwide, of 135,000-pound twin 48-foot double trailer combinations, and 115,000-pound triple-trailer trucks. These would be the largest increases in truck size and weight in the nation's history. Yet even these larger rigs would be less fuel efficient than rail by a 2-to-1 margin.

The impact of bigger trucks on the rail industry would be devastating, diverting up to 20 percent of rail ton-miles to the highways and reducing rail net revenues (profits) by up to 50 percent. The truckers' proposal amounts to a recommendation that America move to an almost exclusively highway-based system of freight transportation. Having just fought a war, one of whose elements was energy supplies, any move to increase truck sizes and weights seems exquisitely ill-timed due to the impact it would have on railroads, rail shippers, and the general public.

We urge the Committee to delete Section 5008 from the bill, or in the alternative, to expand the provision to cover all forms of energy affected by the Clean Air Amendments of 1990 and "other Federal policies." Continued unique treatment of railroads cannot be justified.

Sincerely,

W. H. Dempsey

APPENDIXES TO MARCH 19, 1991 HEARING

(Subtitle A of Title III)

Appendix I—Responses to Additional Questions

Department of Energy
Washington, DC 20585

April 11, 1991

The Honorable Timothy E. Wirth
Chairman
Subcommittee on Energy Regulation and Conservation
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

On March 19, 1991, B. Reid Detchon, Principal Deputy Assistant Secretary for Conservation and Renewable Energy testified before your subcommittee on the Building Energy Efficiency Standards Provisions of S. 341.

Following the hearing, you submitted written questions on behalf of yourself and Senator Wallop to supplement the record. Enclosed are the answers to those questions.

If we can be of further assistance to you or your staff, please contact our Congressional Hearing Coordinator, Valerie Howard, on (202) 586-2032.

Sincerely,

Jacqueline Knox Brown

Jacqueline Knox Brown
Assistant Secretary
Congressional and Intergovernmental
Affairs

Enclosures

QUESTION FROM SENATOR WIRTH

Question 1: Several witnesses in their statements later this afternoon will recommend that the voluntary industry consensus standards, such as ASHRAE 90.1 and CABO-MEC, and not Federal standards, should be the vehicle for transferring building energy standards to the marketplace.

Do you think DOE can promote energy savings most effectively by developing Federal building standards, or by supporting the industry consensus standards?

Answer: To promote energy savings most effectively it is important that DOE both develop Federal building standards as unbiased models and support the development of industry consensus standards. DOE has a statutory obligation to develop and promulgate energy conservation standards for new buildings (Energy Conservation Standards for New Buildings Act of 1976, as amended). The Act requires the Department to promulgate national standards that are mandatory for Federally-owned buildings and are voluntary for all other buildings. The Federal government, as both a builder and long-term owner/occupant of buildings, has a responsibility to see that its buildings include cost-effective, energy-saving features. This also provides a valuable model for State and local governments and private sector owners with a similar perspective.

The largest amount of construction is non-Federal, and its energy features are controlled by State and local building energy codes. These codes are based on either national or regional model codes or national building industry consensus standards. The model codes (such as the CABO MEC-1989) are in turn based on the consensus standards. Therefore, DOE since the early 1980s has worked closely with building industry consensus organizations in the development of building energy standards. For example, DOE worked hand-in-hand with the American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE) and Illuminating Engineering Society (IES) in the development of commercial building and multi-family high rise residential building standards, first by funding an ASHRAE Special Project Committee that developed the rudiments of the current ASHRAE and DOE standards, and then by providing technical support to the ASHRAE/IES Standard 90.1 Committee.

DOE entered into these agreements with ASHRAE for two distinct reasons. First, ASHRAE commercial building standards are used by most States as the basis for building codes, and the organization was the most appropriate initial recipient of DOE technical assistance. Second, DOE is extremely cognizant of our role in providing up-to-date technical assistance to groups that have the greatest effect on increasing energy efficiency in buildings.

DOE's main building standards mission is to assure that national, state, or local standards produce buildings that are designed and built to maximize energy efficiency and the use of renewable resources, to the extent practicable, while improving or maintaining habitability, cost-effectiveness, and environmental standards. DOE views its role as a responsible, impartial, and technically competent party in the standards development process. In conformance with its mandate, it proposes to continue to establish standards for Federal buildings, while maintaining a strong working relationship with other Federal agencies, such as HUD, who have the responsibility for building loan and loan guarantee programs, and with voluntary, national standards and code organizations that State and local governments look to for support.

QUESTION FROM SENATOR WIRTH

Question 2: Under current law the Department is required to monitor activity at the State level regarding building energy codes.

Can you briefly summarize which codes are used at the State and local level? For example, how many States or localities have mandatory building energy codes for residential or commercial buildings, and how stringent are they?

Do you have any information regarding the actual enforcement of the codes?

Answer: Under Section 311 of the Energy Conservation Standards for New Buildings Act of 1976, as amended, the responsibility for monitoring State activity falls with the U.S. Department of Housing and Urban Development and not DOE. However, DOE does maintain some general information about State building codes. In 1989, State jurisdictions based their energy codes on the following codes and standards: (1) Energy Conservation in New Building Design, ASHRAE Standard 90-75, in four states; (2) ANSI/ASHRAE/IES Standard 90A-1980, in eleven states; (3) ASHRAE Standard 90.1P in one state; (4) the BOCA Basic Energy Codes of 1986 and 1987 (BEC-86 and BEC-87) in five and seven states, respectively; (5) the Model Code for Energy Conservation in New Building Construction 1977 (MCEC-77) in 7 states; (6) the 1983 Model Energy code (MEC-83) in 6 states; (7) the Model Energy Code 1986 (MEC-86) in six states; (8) the 1977 Uniform Building Code in three states; (9) the 1985 Uniform Building Code in one state; and (10) six states used codes developed internally. (Some States used two or more codes in different areas.) (See attached summary.)

STATE CODE REQUIREMENT SUMMARY - 1989

ORGANIZATION/ CODE OR STANDARD	TECHNICAL BASIS	NUMBER STATES USING
ASHRAE		
Standard 90-1975	NBS/ASHRAE SPC	4
ANSI/ASHRAE/IES Standard 90A-1980	ASHRAE/IES SPC	11
ASHRAE/IES Standard 90.1P	ASHRAE/IES SSPC	1
BOCA		
BOCA-86	MEC-86	5
BOCA-87	MEC-86	7
CABO		
MCEC-77	ASHRAE Standard 90-75	7
MEC-83	MCEC-77/ASHRAE Standard 90A-1980	6
MEC-86	MEC-83/ASHRAE Standard 90A-1980	6
ICBO		
UBC-77	MCEC-77	3
UBC-85	MEC-83	1
Various States/State Codes	State code organizations	6

ANSI	American National Standards Institute
ASHRAE	American Society of heating Refrigerating and Air-conditioning Engineers, Inc.
BOCA	Building Officials Conference of America
ICBO	International Conference of Building Officials
MCEC	Model Code for Energy Conservation in New Building Construction (DOE/NCSBCS)
MEC-	Model Energy Code (CABO)
NBS	National Bureau of Standards (National Institute of Standards and Technology)
UBC	Uniform Building Code (ICBO)

In 1989, 48 states had some form of energy conservation code or standard for at least some of their new buildings. (Louisiana and South Dakota had none.) These codes or standards differ significantly in their technical criteria, the type of buildings or occupancies covered, the procedures for compliance, and the level within the state that the code is promulgated.

Some states have one code or standard for state-owned buildings and another for private construction. Other states have a code or standard for residential buildings and not for commercial buildings and vice versa. Still other states exempt some classes of buildings, such as schools. Finally, some states cover all buildings in their jurisdictions.

Within the above context, some codes are mandatory throughout the state (24 states), some are mandatory if adopted by local or municipal jurisdictions (15 states), and still others are mandatory only for incorporated jurisdictions.

DOE has not done a comparison between state-adopted codes. The stringency of the codes and standards adopted also varies considerably. One indication of stringency is the date the technical criteria were developed on which the code or standard is based. Some are based on criteria developed as early as 1975, while others have been updated or were adopted at a later date, based on 1980 or 1986 criteria. In 1989, approximately 43 states had codes or standards based on criteria developed in 1980 or before.

With regard to enforcement, DOE has no statutory responsibility to monitor the enforcement activities of States and local governments. The 1976 Act places such a requirement on HUD. We have not conducted a code enforcement study.

QUESTION FROM SENATOR WIRTH

Question 3:	Generally, how much more stringent are DOE's commercial building energy standards than those of ASHRAE, and how do you expect DOE's residential codes will compare with CABO-MEC?
Answer:	The DOE commercial and multi-family high rise standards would result in one to eleven percent less energy use than ASHRAE's, depending on building type and effective date of criteria. The DOE residential multi-family high rise standards would result in 10 to 20 percent less energy use than the CABO MEC-89. The DOE residential standards are expected to result in from one to ten percent less energy use than the CABO MEC-89, depending on climatic area and building type.

The DOE commercial and multi-family, high-rise residential building standards and ASHRAE 90.1-1989 are substantially the same. These two standards are the result of a cooperative effort between DOE and ASHRAE. The effort began in 1982 with a joint research project that developed recommendations for future standards. DOE and ASHRAE then worked together to turn the recommendations into credible standards. Throughout this process, ASHRAE provided the forum for standards development, along with the technical expertise of its membership. DOE served by participating in its own standards development process and by conducting relevant research and providing technical assistance to ASHRAE. There are some minor differences between the two standards. The first is with respect to Heating, Ventilation, and Air Conditioning (HVAC) equipment efficiencies. ASHRAE adopted efficiency levels for 1989 and then more stringent levels for 1993; DOE adopted the more stringent levels immediately. This was done because the DOE standards are mandatory for the Federal sector and we believe that the Federal sector should be used as a model for all other sectors. The second difference appears in the lighting requirements. DOE provides lighting performance levels for 1989 and then more stringent levels in 1993; ASHRAE adopted only the 1989 levels.

The CABO Model Energy Code (MEC-89) is a derivative of the ASHRAE Standard 90A-1980. Although it has been modified over the years, some parts are almost twelve years old. The proposed DOE standard is expected to provide much greater design flexibility, along with increased stringency in some areas. DOE believes that the voluntary residential standard that it will be proposing this summer will be a technical and cost-effective improvement to current residential energy standards. A joint DOE/ASHRAE Special Project Committee worked over a three-year period to develop recommendations and a computer program that is the basis for the standard. DOE will make its standard available to all voluntary consensus standards and code groups, including ASHRAE and CABO, to update their codes and standards. DOE sees itself as a major, unbiased partner in the development of the consensus standards and is very willing to work with these groups and State and local governments in the adoption of improved standards.

QUESTION FROM SENATOR WIRTH

Question 4: On page 2 of your statement you say that the Department plans to "work under existing authority to . . . . strengthen the energy efficiency standards for all Federally assisted new housing, including manufactured housing and residential housing subject to mortgages under the National Housing Act".

Could you be more specific regarding your "existing authority", under the National Housing Act, to expand building standards to residential housing subject to mortgages under the National Housing Act?

Answer: In my testimony I stated that, "We plan to work under existing authority with the Department of Housing and Urban Development (HUD) and other Federal agencies to strengthen" standards for various types of Federally-assisted housing.

I was referring to an expansion of existing DOE-HUD cooperation in the standards area. HUD has the most specific statutory responsibility affecting housing subject to mortgages under the National Housing Act. The HUD authority is contained in Section 109 of the National Affordable Housing Act. The Act says, in part:

> The Secretary of Housing and Urban Development shall, not later than one year after the date of enactment of this Act, promulgate energy efficiency standards for new construction of public and assisted housing and single-family and multifamily residential housing (other than manufactured homes) subject to mortgages under the National Housing Act. Such standards shall meet or exceed the provisions of the most recent edition of the Model Energy Code of the Council of American Building Officials and shall be cost-effective with respect to construction and operating costs.

In addition, DOE intends to work with the United States Department of Agriculture (USDA), which provides mortgage insurance through the Farmers Home Administration and the

Department of Veterans Affairs which provides mortgage insurance through Veterans Administration loans. The National Energy Strategy (NES) calls for the use of energy efficiency standards for "all new buildings subsidized by Federal funds or Federally-insured mortgages." This includes not only housing, but other new buildings as well.

QUESTIONS FROM SENATOR WIRTH

Question 5:	Could you please provide a history, from 1975, of DOE's budget for providing technical assistance to State and local governments to encourage the strengthening of building energy standards?
Answer:	The passage of the Energy Policy and Conservation Act of 1975 tied the establishment of State building standards to the receipt of Federal energy conservation grant funds. DOE's predecessor agency, the Federal Energy Administration, established grant guidelines that required that States adopt building standards that were at least as stringent as ASHRAE Standard 90-1975. Within a few years most States had adopted the ASHRAE standard, its equivalent, or had gone beyond that level. Since 1975, the DOE grant guidelines have been modified to require ASHRAE Standard 90A-1980, the successor to the earlier standard. DOE is not statutorily responsible for the implementation and technical assistance under the Energy Conservation Standards for New Buildings Act; that responsibility lies with HUD per Section 308 and 310 of the Act. However, since 1978 and the inception of DOE's own development of building standards, the DOE office that is responsible for developing building standards has maintained some interaction with the States through workshops, professional organizations, and indirectly through the DOE State grant program.

DOE has asked for substantial increases in funds for the program in its FY 1991 and FY 1992 budgets, in part, to strengthen its technical assistance to State and local governments. In its FY 1991 budget request, DOE requested $5 million, compared with the $742,000 appropriated in FY 1990. In FY 1992, DOE is requesting $5.2 million. DOE sees great benefit in more State and local government involvement in the development, implementation, and training programs necessary for these standards to be successful.

QUESTIONS FROM SENATOR WIRTH

Question 6: You say that you plan to aggressively encourage the adoption of building energy standards by State and local governments by giving awards to "High Value, Energy-Efficient Buildings".

What other strategies have you considered to encourage the adoption of standards, and have you considered any incentives, such as grants, or disincentives, such as the withholding of certain Federal funds or mortgage insurance?

Answer: DOE proposes an aggressive program to inform and work with architects, engineers, and builders and Federal, State, and local code officials to implement the standards. We will assist these groups to understand the technical basis for the standards, how they relate to existing codes and standards, how they can best be incorporated in existing codes and standards, how they relate to existing design and construction practices, how to take maximum advantage of the design flexibility embodied in the standards, and how to check for design and then construction compliance. Education and training materials will be developed for the broad spectrum of people involved. We also will work with architects, engineers, and code officials to reduce the time and effort required to comply with the codes and standards.

Direct grants to encourage the adoption of the standards are not proposed in this budget. Such a program will be expensive and is unnecessary. Already, there is strong interest in the adoption and implementation of standards and codes. The primary barrier is lack of information, and we intend to use a number of excellent channels for dissemination of information on DOE's standards program.

In addition, the National Energy Strategy proposes that: "All new buildings subsidized by Federal funds or Federally-insured mortgages be required to meet cost-effective, energy-efficiency standards, which, at a minimum, are equivalent to the standards or codes currently recognized by major national organizations." Currently, DOE is working with other Federal agencies to develop a plan for implementing this proposal.

QUESTIONS FROM SENATOR WIRTH

Question 7: On page 3 you recognize the importance of local enforcement in determining the success of standards.

Can you describe any current or planned DOE activities designed to encourage or improve enforcement of building energy codes?

Answer: Now that DOE is completing the development of interim standards, we are giving increased attention to the importance of local enforcement to successful standards programs. The need for these programs is highlighted in the National Energy Strategy. These programs will include working with codes and standards organizations to educate and train code officials and working with building, architectural, engineering, and lighting organizations on programs to train building designers on the use of the new standards.

QUESTION FROM SENATOR WIRTH

Question 8: On page 3 you state that the "success of the standards will depend on the degree to which they are implemented and enforced at the local level. Accordingly, we have proposed in our Fiscal Year 1992 budget request an aggressive program to inform architects and engineers and State and local code officials about the Standards."

Could you describe your buildings related budget and where this new initiative fits into that budget -- For example, how much goes into research, how much into the development of standards?

Answer: The buildings related budget supports a strategy to reduce energy demand through conservation and efficiency improvements and increase the use of renewable energy technologies within the buildings sector. The program combines effective and expanded R&D activities with aggressive information and technology transfer and market conditioning through expanded appliance standards and voluntary building energy guidelines. The new initiative predominantly fits within the demand reduction portion of the strategy, although renewable energy technologies are addressed and will increase as research produces practical technologies.

The FY 1992 building technologies program request is $55.2 million. The standards portion of that budget is $7.7 million, including $5.2 million for building standards and guidelines and $2.5 million for appliance standards. Of the $5.2 million for building standards, $3.0 million will be used to support an aggressive program to inform architects and engineers and State and local code officials about the building standards. The standards activities also benefit from DOE's research and development programs in such areas as indoor air quality, infiltration and ventilation, and building design, modeling and performance simulation areas. The DOE building standards embody the public and private building research results of the last 10 to 15 years. The DOE standards are proposed for use by model codes and building industry consensus standards organizations as updates to codes and standards, some of which have not been significantly revised since 1980.

QUESTION FROM SENATOR WALLOP

Question 1a: The Department's proposed building energy efficiency standards for residential construction will be published in June. Generally, how do you expect those standards to differ from the CABO Model Energy Code?

Answer: The Department intends to propose standards that will achieve the maximum practicable improvement in energy efficiency and increase the use of nondepletable sources of energy. The Department has examined a number of state and national building codes, including the CABO Model Energy Code, 1989 (MEC-89) with respect to energy use and life cycle cost. We believe that the proposed rule will be cost effective and result in greater energy savings than other standards, including the MEC-89. The advantages will be in an improved optimization of envelope and heating, ventilation, and air conditioning (HVAC) equipment features and the ability to tailor the proposed standards to over 800 locations in the country.

QUESTION FROM SENATOR WALLOP

Question 1b: In their written testimony, the various representatives from the building industry suggest that the appropriate role for the Department is one of research, education and coordination of efforts in this area. What is your opinion as to the appropriate role of the Department?

Answer: The Department agrees with the testimony that research, education, and coordination are appropriate roles for DOE. However, DOE disagrees with the testimony that the development of energy efficiency standards should be left exclusively to other organizations, such as CABO. DOE believes that it should be responsible for developing energy efficiency standards that are applied to the Federal government's own buildings and used as a model for other standards, especially those applied to new buildings where the Federal government has a financial interest, such as public and assisted housing, and to housing subject to mortgages under the National Housing Act, Department of Veterans Affairs, and the Farmers Home Administration programs.

The Federal rulemaking process assures a neutral decisionmaking body and provides a process open to all individuals interested in the development of the building energy efficiency regulations. DOE's standards are based on the results of the latest energy efficiency research activities conducted by DOE and others.

DOE works actively with the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) to transfer the results of our R&D to ASHRAE and to provide a common technical foundation for the DOE and ASHRAE commercial building standards. We have not worked as actively with CABO in the residential standard area, although some DOE laboratory researchers have been active in this process and DOE intends to participate more actively with CABO in the future.

As a result of this cooperation, the DOE and ASHRAE commercial building standards are similar, except in a few areas where DOE requires more energy-conserving features, such as 1993 lighting efficiency levels. We believe cooperation with CABO can achieve similar agreement. The active participation by DOE helps ensure neutrality among the different interests, such as the insulation, masonry, and equipment manufacturers, that participate in the standards-making process.

The different processes used by DOE and by ASHRAE and CABO make it difficult to end up with standards that are identical in all respects. ASHRAE uses a consensus process that achieves wide agreement, if not uniformity, among those participating in the standard-making process. CABO uses a combination of a consensus process and approval by national and regional code organizations. DOE uses a regulatory and public hearing process where the standards must reflect the statutory requirements and the rulemaking record. However, by cooperating in each others processes, any differences can be minimized.

After working with ASHRAE and CABO to develop standards, we continue to work with these organizations to promote the standards; to develop materials to educate those affected by the standards, e.g., builders, designers, building code officials, and others; and to continue research directed at future improvements to the standard.

QUESTION FROM SENATOR WALLOP

Question 1c: Does the Department believe it is desirable to substitute the DOE standards for those required by the Cranston-Gonzales Affordable Housing Act for federally assisted housing and, if so, why?

Answer: Yes, once the DOE standards are final. DOE believes that its standards are likely to be more energy conserving and more cost effective, and would permit more optimized selection of energy conservation and renewable measures.

The Council of American Building Officials (CABO), which developed the Model Energy Code (MEC) referred to in the National Affordable Housing Act, is governed by a Board of Directors made up of representatives of the National Council of States on Building Codes and Standards and three regional organizations of State and local building code officials. Each of these four organizations has the power to veto any increase in the stringency of the CABO-MEC standards. DOE intends to work closely with CABO to seek to obtain the closest possible agreement between the DOE and CABO standards. However, we believe the primary reliance on standards affecting Federally-owned and Federally-insured buildings should be placed with the Federal government.

QUESTION FROM SENATOR WALLOP

Question 2a.	With respect to residential energy efficiency ratings, the Administration suggests that voluntary guidelines such as those proposed in S. 341 should become mandatory after five years. Under what statutory authority does the Department propose to make these systems mandatory?
Answer:	The Department has no statutory authority to make a home energy rating system mandatory, but other Federal institutions may have such authority. The National Energy Strategy (NES) proposed that: "After at least 5 years of support for voluntary adoption, it will be required that information on energy efficiency and information on the available mortgage financing options be provided to home buyers prior to sale." To implement this proposal, the Department has initiated a collaborative effort with the home building and home financing industry to establish such a voluntary program. We hope that these voluntary efforts will be successful and that they will be sufficient to ensure widespread availability of energy efficiency ratings and information on the availability of energy-efficient mortgages.

QUESTION FROM SENATOR WALLOP

Question 2b. How would these mandatory "ratings" be enforced in the marketplace?

Answer: There are a number of different ways to require the provision of information on homes at the time of sale. DOE will evaluate these different approaches and, if necessary, make specific legislative proposals. One approach might be to require ratings for all home sales financed through Federally-insured mortgages or through financial institutions that receive Federal deposit insurance.

QUESTIONS FROM SENATOR WALLOP

Question 2c:	What mortgage financing incentives are now available or are being proposed by the Administration to enforce use of these ratings?
Answer:	Federal Housing Administration (FHA), Veterans Administration (VA), Farmers Home Administration (FHmA) and the secondary mortgage market have permitted mortgage incentives for energy efficiency for a number of years. To date, these programs have been little used, and generally they have not been linked to verified home energy rating systems. However, these efforts have been strengthened by Sections 109 and 496 of the National Affordable Housing Act of 1990, which require the Department of Housing and Urban Development to link energy efficiency to housing finance. As indicated earlier, the Department of Energy, in cooperation with the Department of Housing and Urban Development, initiated in March a collaborative process designed to involve all the organizations responsible for, and interested in, home energy rating systems and the procedures required to link them to mortgage financing. These include VA, FHmA, the secondary mortgage market, primary lenders, real estate agents, and the housing industry. The objective of this collaboration is to

develop the procedures required for a valid, uniform home energy rating system and to facilitate the development of uniform energy efficiency financing mechanisms by those organizations responsible for home financing.

QUESTION FROM SENATOR WALLOP

Question 2d: Do these mortgage "incentives" include conditioning a federally insured mortgage on the achievement of a certain rating?

Answer: No. The mortgage incentives would not condition a Federally-insured mortgage on the achievement of a certain rating.

QUESTION FROM SENATOR WALLOP

Question 2e: If such a condition were imposed, what practical effect do you envision this would have on a home seller?

Answer: As indicated above, the program would not condition mortgages on the achievement of a certain rating. Such a requirement could be quite disruptive of the home resale market by preventing or substantially delaying thousands of home sales, regardless of the willingness of prospective buyers to purchase a less energy-efficient home.

QUESTION FROM SENATOR WALLOP

Question 2f:	What effect would such a requirement have on the private mortgage market?
Answer:	A mandatory efficiency requirement of this type could be very disruptive of the private mortgage market and would be strongly opposed. However, efforts that would lead to the provision of more information to prospective home buyers could have positive effects. The high energy costs associated with energy inefficient housing may be a factor in a marginal buyer's inability to make mortgage payments, particularly at a time of rising energy costs. Thus, the mortgage market might experience some reduction in the risk of bad loans as a result of the increased attention that would be given to energy efficiency in home sale transactions if energy efficiency ratings were provided widely. To ensure that the concerns and needs of the mortgage industry are addressed in the effort to link home energy rating systems with home financing, the mortgage industry is a participant in the collaborative process discussed previously. Their participation is also designed to ensure that the resulting procedures can be implemented easily.

Owners of energy-efficient homes could benefit from the added value associated with efficiency. The owners would have a rating derived from verified procedures to prove to potential buyers and their mortgage companies that efficiency claims are valid.

Appendix II—Additional Material Submitted for the Record

Polyisocyanurate Insulation Manufacturers Association

April 8, 1991

The Honorable Timothy E. Wirth
Subcommittee on Energy Regulation
and Conservation
380 Russell Office Building
Washington, DC 20510

Dear Senator Wirth:

During the Subcommittee hearing on the role of building standards in promoting energy efficiency, you asked me to elaborate on PIMA's suggestion that economic incentives be used to encourage the private sector and states to exceed appropriate minimum standards. Specifically, you requested three examples of such economic incentives.

At that time, I indicated PIMA's support for energy efficient mortgages as a important means by which the financial community can, in very real terms, demonstrate the link between energy efficiency and the cost of home ownership. I also requested the opportunity to supplement my response in writing.

In PIMA's view, offering economic incentives to the private sector to exceed minimum standards, and to states to meet or exceed standards, represents an important policy tool to advance energy efficiency. In addition to energy efficient mortgages, there are a variety of other options worth exploring:

- **Tax credits**. Just as Congress has deemed it appropriate to offer tax credits for energy production, credits should be offered to builders that construct buildings that exceed appropriate minimum standards;

- **Grant Monies**. The federal government provides states with significant funds to implement a variety of energy efficiency programs. PIMA believes it is appropriate to link such funding to the implementation of state building standards that meet minimum federal requirements. To the extent states adopt standards that exceed federal standards, they should be eligible for additional funding. If, on the other hand, the state standards fail to meet the federal standards, and the federal standards would be cost-effective, federal funding of state programs should be decreased.

1001 Pennsylvania Avenue N.W. • 5th Floor • Washington, D.C. 20004
(202) 624-2709, Fax (202) 628-3856

- **Ratepayer Support.** The construction of energy efficient buildings assist utilities in holding down utility bills. State regulatory agencies should be encouraged to consider appropriate incentives for builders. One such possibility is offering free "line extensions", the cost to the utility for hooking up a new development to the utility system, when the developer exceeds the appropriate standard.

PIMA believes that each of these economic incentives are worthy of your consideration as S. 341, the National Energy Security Act of 1991, moves through the Committee and to the Senate floor.

On behalf of PIMA, thank you again for the invitation to participate in the Subcommittee's deliberations on the role of building standards, and for your continued leadership on energy efficiency issues.

Sincerely,

William Jelin
President, NRG Barriers, Inc.

On behalf of
Polyisocyanurate Insulation
Manufacturers Association

WJ:ss

Libbey
Owens
Ford
A member of the Pilkington Group.

Mar 19

STATEMENT OF

LIBBEY-OWENS-FORD CO.
Toledo, Ohio

before a joint hearing of the

U.S. SENATE

SUBCOMMITTE ON

ENERGY REGULATION AND CONSERVATION

COMMITTEE ON ENERGY AND NATURAL RESOURCES

regarding

THE NATIONAL ENERGY POLICY

WASHINGTON, D.C.

MARCH 19, 1991

For Further Information Contact:
Libbey-Owens-Ford Co.
Peter F. Gerhardinger
(419) 247-3931
or
William C. Sellery, Jr.
(202) 289-1780

PILKINGTON

Libbey
Owens
Ford
A member of the Pilkington Group

People all over the world are becoming increasingly aware of the fragile state of our environment and recognizing the need to operate more energy efficiently. In that regard, the federal government can, and should, play a particularly important role in helping America become both energy efficient and energy independent. It is critical that the federal government provide both leadership and incentives for the general population to conserve energy.

In regards to conservation, there exists a mechanism to encourage the general population to upgrade the energy efficiency of their homes, buildings, automobiles, and appliances, through the mechanism of an energy tax credit. Such a tax credit was enacted by the Energy Tax Act of 1978, but has since expired in 1985. House Committee report --- (p.217) points out that, "Generally it found that the energy conservation credit has achieved its purpose". We believe that it is time once again to encourage conservation, through such a credit, as an integral part of a national energy policy. We believe that there has been substantial progress made at introducing new energy efficient construction products since 1985, and that a renewal of the energy tax credits would spur the speedy adoption of such energy efficient products.

Another important influence in energy efficient windows is the formation of the National Fenestration Rating Council (NFRC), made up of Industry, Government and Utility representatives, with the intent of developing a credible, fair window rating and labeling system recognizing high performance windows, and giving the consumer a guide towards the purchase of energy efficient window products. LOF fully supports the activities of the NFRC, and encourages government funding and support for this activity.

As an example of practical application, window glass technology has made dramatic advances with respect to energy efficiency - advances far more dramatic, and with significantly greater net energy gains, than ever before. The practical application of new technology in something as simple and everyday as a window can translate into one of the best ways to achieve our goals of energy efficiency and independence. Natural energy sources, like the power of the sun, can now be efficiently captured through windows.

In that regard, it would be useful to describe what may appear to be an everyday product, but, through the application of breakthrough technology, becomes one of the most efficient yet practical ways to save significant amounts of energy on a global basis - which the federal government now has the opportunity to encourage in the United States.

LOF Libbey
Owens
Ford
A member of the Pilkington Group

A decade of research and development by Libbey-Owens-Ford Co. resulted in the most dramatic breakthroughs in energy efficient window glass in the past 30 years -- a new "low E" glass that actually provides a net energy gain within a home or building instead of an overall energy loss; plus a new batch-tinted glass offering an unprecedented combination of solar control, UV Blockage, and high daylight transmittance.

Low E, or "Emissivity", is a generic description for a glass product that has a special coating to improve its insulating ability. While a low E coated window is letting the warmth of the sun into the room, it's also preventing the already heated indoor air from escaping. Even this simple explanation makes it easy to appreciate the value of low E glass in everyday applications.

Low E products have been around for a few years, attracting a growing number of enthusiasts because of their heat management properties. Recent technological breakthroughs by Libbey-Owens-Ford Co. have now improved those properties to the point where a viable, free source of net energy gain is created. Windows can now be used as energy sources, an incredible attribute.

This low E coating is produced as part of the glass manufacturing process. As such, it is literally fused into the surface and is as durable as glass. Also, the coating is COMPLETELY colorless, such that there is no appearance penalty in using this glass in windows.

The practical application of this technology on a nationwide basis could have dramatic implications. For example, on an annual basis, windows in the United States are known to consume 4 % of the total annual energy budget. This equates to around 600,000,000 barrels of oil per year. Using currently available technology, this figure could be reduced by 40 %, which would drop this consumption to 240,000,000 barrels of oil per year. This drop would not only provide a direct economic benefit, but perhaps more importantly would provide greater energy independence while positively impacting the ecological problems associated with fossil fuel consumption.

Upgrading a window from double glazing (two panes of glass) to high performance low E double glazing will save over 250 gallons of oil over the life of the window, as determined by the Lawrence Berkeley Laboratory, Building Science Division, a laboratory of the U.S. Department of Energy. Low E coatings have been remarkably successful in the building industry to date, capturing about 20 % of the total window market since their introduction in 1982. But that means that four out of every five windows sold last year could have used low E but did not. Additionally, there are about 20 to 25 billion sq.ft. of glass in existing windows that could be replaced or retrofitted with LOF's durable hard-coat low E glass. A very rough estimate of what that would mean to the U.S. is a savings of 170,000,000 of barrels of oil every year, or about 30 % of the Alaskan oil pipeline, which is worth nearly $ 6 billion a year.

PILKINGTON

In the southern parts of the United States the Low E product can be combined in a window with LOF's new batch-tinted glass to minimize solar energy gain during the cooling season to reduce air-conditioning loads, while maintaining high daylight transmittance (important to minimize artificial lighting expense), and block the ultra-violet (UV) transmittance to minimize carpet and furniture fading.

In conclusion, we believe the message is simple. We would encourage the federal government, both the administration and congress, to take a fresh look at energy conservation as a key component of a national energy policy. Towards that end, we believe that windows and new glass technologies can play a key role in this conservation effort. Libbey-Owens-Ford Co. believes that practical opportunities exist today for the federal government to lead the nation toward energy efficiency and energy independence.

APPA

American Public Power Association

2301 M Street, N.W.
Washington, D.C. 20037-1484
202/467-2900

Statement of the
AMERICAN PUBLIC POWER ASSOCIATION
on
Provisions of Title III of S. 341
on
Building Energy Efficiency Standards and Ratings
before the
SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

March 19, 1991

The American Public Power Association supports the provisions of S. 341 designed to increase energy efficiency in residential dwellings. Increasing the wise use of existing resources must be a cornerstone of any comprehensive national energy plan, and home energy efficiency must be a primary target of that effort. APPA also recommends certain additions to strengthen the proposals contained in Title III of S. 341.

The American Public Power Association is the national service organization representing more than 1,750 locally controlled public power systems. Public power has long supported efforts to improve the efficiency of electric production and use. APPA believes that the provisions contained in Title III provide an excellent starting point for improving the energy efficiency of American homes.

Residential Efficiency

Residential users consume more than one third of all electricity generated in the United States. More than fifty percent of this electricity is used for space heating and conditioning. Thus, provisions designed to improve the efficiency of the building envelope -- such as efficiency standards for federally assisted housing, energy rating systems, and efficiency standards for windows and lighting fixtures -- can provide sizable national energy savings.

Such standards can also provide substantial savings to electric consumers. In 1989, consumers spent approximately $160 billion on electric utility services. Cost-effective energy efficiency improvements can provide considerable cost savings to electric consumers, thereby increasing their disposable income. The Electric Power Research Institute (EPRI) estimates that by the year 2000, 24 to 44 percent of electricity consumption could be saved through various efficiency improvements in electric production and use. Federal programs to improve energy efficiency are particularly important for individuals and families on low or fixed incomes. These consumers frequently do not own their dwelling and cannot afford the upfront cost of installing energy efficiency and conservation equipment. Federal efforts to improve the energy efficiency of publicly assisted housing are particularly valuable.

Section 3001 of S. 341 would promote the development of minimum energy efficiency standards for all public and publicly assisted housing, as wel as houses subject to mortgages under the National Housing Act. A considerable portion of the income of low and fixed income families is spent on energy services. Unfortunately, many of these individuals cannot afford to install energy efficiency equipment that would reduce monthly energy bills. Establishing minimum energy efficiency standards for publicly assisted housing will ensure that the energy dollars of low and fixed income individuals and families are well spent. To ensure that these standards achieve the desired result, a reasonable baseline should be established in the legislation. APPA therefore recommends that the standards developed under this provision meet or exceed the standards of the then current version of the Council of American Building Officials' model energy code.

Some states and utilities use energy rating systems, such as the Super Good Cents program, to promote the construction and purchase of energy efficient houses. APPA supports the development of national guidelines for energy efficiency ratings and efforts to encourage the use of such ratings. Section 3002 of S. 341 would provide important assistance to states that are seeking to implement such programs. Again, APPA recommends strengthening this provision by requiring that these standards must meet, at a minimum, the model energy code developed by the Council of American Building Officials.

Manufactured and mobile housing are not covered under Title III of S. 341, yet these units are frequently inefficient and inhabited by individuals and families on low and fixed incomes. APPA recommends amending Title III to require the Department of Housing and Urban Development to promulgate energy efficiency standards for mobile and manufactured housing. These standards should be developed in consultation with utilities, representatives of the manufactured housing industry, and consumer groups and should be designed to reflect regional variations in climate and energy consumption patterns.

Standards for Windows and Lighting

Section 3006 and Section 3008 require, respectively, the development of energy efficiency labels for windows and lighting fixtures. APPA recognizes the value of this information to consumers, but recommends amending these provisions to require the development of minimum efficiency requirements for both windows and lighting fixtures.

The value of national energy efficiency standards is demonstrated by the success of the Appliance Efficiency Standards Act. This statute, developed with the support of industry and consumers, provides important consumer information and ensures that new appliances meet minimum efficiency standards.

While labelling requirements will provide important consumer information, they are not enough. Frequently, the selection of windows and lighting fixtures for new houses and businesses are made by the builder and not the future resident. Consequently, these purchases are made primarily on the basis of upfront capital costs rather than the life cycle costs of the decision. These short-sighted decisions result in inefficient energy consumption that is avoidable.

The mandate of minimum efficiency standards for windows and lighting fixtures
will insure that more cost-effective products are purchased and installed.

Utility Rebates for Energy Efficient Equipment

Many electric utilities offer their consumers rebates for the purchase and installation of energy efficient equipment in order to defray the higher upfront cost of these investments compared to less efficient devices. Studies have shown that these programs dramatically increase consumer participation in utility-sponsored energy efficiency programs.

However, the Internal Revenue Service ruled recently that these utility cash rebates are to be included in the recipient's gross income and subject to taxation. Taxing rebates clearly reduces the value of the incentive and the probability that customers will invest in energy efficient equipment.

APPA urges the committee to include in S. 341 a provision, similar to that included in S. 83 and H.R. 1007, that would exempt from federal taxation cash rebates given by utilities to customers for conservation expenditures.

Conclusion

In order for a national energy package to succeed, it must be balanced, comprehensive and fair. The encouragement of energy efficiency must be included for any proposal to meet these tests.

APPA supports the inclusion in S. 341 of provisions designed to improve the energy efficiency of buildings through the implementation of the policies outlined above.

APPENDIXES TO MARCH 21, 1991 HEARING

(Subtitle A of Title IV)

Appendix I—Responses to Additional Questions

Department of Energy
Washington, DC 20585

April 8, 1991

The Honorable Timothy E. Wirth
Chairman
Subcommittee on Energy Regulation and Consvervation
Committe on Energy and Natural Resources
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

On March 21, 1991, George E. Helland, Jr., P.E., Deputy Assistant Secretary for Export Assistance, Office of International Affairs and Energy Emergencies testified before your subcommittee on Subtitle A of Title IV of S. 341, regarding the Export of Renewable Energy and Energy Efficiency Technology.

Following the hearing, you submitted 6 written questions to supplement the record. Enclosed are the answers to those questions.

If we can be of further assistance to you or your staff, please contact our Congressional Hearing Coordinator Renee Wilhite on (202) 586-4277.

Sincerely,

Jacqueline Knox Brown

Jacqueline Knox Brown
Assistant Secretary
Congressional and Intergovernmental
Affairs

Enclosures

QUESTIONS FROM TIMOTHY E. WIRTH

Question 1(a): Does the creation of an Office of Export Assistance mean that export programs for renewable and efficiency technologies will receive higher priority?

Answer: Yes, creation of this office reflects the importance the Department of Energy places upon exports of all forms of energy products. It brings marketing expertise to bear on the export-related programs of the Department to help guide what had previously been primarily technical programs.

Question 1(b): Will CORECT be moved from Conservation and Renewables to the Office of International Affairs and Energy Emergencies? How will staff and funding resources be allocated under this new arrangement?

Answer: The day-to-day operations of CORECT will remain the responsibility of the Office of Conservation and Renewable Energy (CE). However, all Departmental activities to foster increased U.S. energy and energy technology exports are now coordinated by the Office of Export Assistance in the Office of International Affairs and Energy Emergencies (IE). The Office of Export Assistance provides overall policy guidance and senior level expertise in marketing and negotiations. This new senior level coordination and expertise will strengthen the CORECT program. At the current level of appropriations, staff levels will remain the same. All program appropriations will support activities consistent with CORECT's established mission.

QUESTIONS FROM TIMOTHY WIRTH

Question 2: You state in your testimony that CORECT is expanding its efforts into Eastern Europe. Which renewable technologies would be appropriate for these countries and does this focus indicate a shift in DOE policy to fossil technologies?

Answer: As part of the DOE's share of funding under the Support for East European Democracies (SEED) Act, P.L. 101-179, and related appropriations acts, we are conducting a variety of activities including a clean coal and energy efficiency demonstration in Krakow, Poland, and support of Energy Efficiency Centers in Warsaw and Prague. Concerning renewables, there is already interest in wind energy in Poland, but we do not have good resource data for wind or other renewable energy technologies to help determine their appropriateness. Therefore, we will conduct an assessment of the general potential for renewables in the East European region.

QUESTIONS FROM TIMOTHY E. WIRTH

Question 3:	You state that you oppose the increased staffing proposed in S. 324 and S. 341, calling current staffing "lean and efficient." How many full time staffers currently work for CORECT and how will the staff evolve under your office?
Answer:	Currently CORECT has the time of a senior manager and a staff assistant in the Office of Conservation and Renewable Energy (CE). This level of support will remain constant and will remain in CE. In addition, we have policy guidance and marketing assistance from the Deputy Assistant Secretary for Export Assistance in the Office of International Affairs and Energy Emergencies (IE).

QUESTIONS FROM TIMOTHY E. WIRTH

Question 4: It seems that feasibility and prefeasibility studies are crucial to the success of renewable export ventures. How does the Department aid in this effort and what goes into one of these studies?

Answer: Several CORECT member agencies fund or cost-share feasibility studies for selected projects, including AID and the Trade and Development Program. The most urgent need, according to industry spokesmen, is for support for prefeasibility analyses which take an initial look at market and project financing possibilities, in less depth than a full feasibility study. CORECT is working with industry to help them find the means to address this issue. Some prefeasibility studies could be shared (and paid for) by multiple companies.

QUESTIONS FROM TIMOTHY E. WIRTH

Question 5:	What role does the Design Assistance Center play in helping to promote renewable exports? What is the current funding level of the center?
Answer:	The Design Assistance Center at Sandia Laboratories is a national resource to provide information and hands-on technical assistance for renewable technologies. Engineers at the Center have assisted a large number of international projects sponsored by organizations such as the World Bank and AID. This year, CORECT supplied $400,000 in funding to the Center, in addition to the $890,000 supplied by the Photovoltaics Program, which is the major sponsor of the Center.

QUESTIONS FROM TIMOTHY E. WIRTH

Question 6: Do the thirteen other agencies under CORECT contribute to the program's budget? If so, how much? If appropriations were to rise to match CORECT's $3 million authorization what would this money be spent on?

Answer: The agencies other than DOE contribute staff time and in-kind services for CORECT activities, but no direct funding. Concerning additional appropriations, DOE is evaluating the potential for increased on-site and State-side education for individuals from foreign countries on the benefits of U.S. renewable technologies. This would be carried out through conferences, trade shows, and seminars based on host country and U.S. industry requests.

Appendix II—Additional Material Submitted for the Record

Agency for International Development
Washington, D.C. 20523

Assistant
Administrator

March 21, 1991

The Honorable Timothy Wirth
United States Senate
Washington, D.C. 20510

Dear Senator Wirth:

Thank you for your interest in A.I.D.'s support for international renewable energy and energy efficiency activities. As you know, A.I.D. has long supported renewable energy and energy efficiency in the developing world, and considers this support to be an integral part of its development assistance efforts.

We believe that the Department of Energy will be best able to provide you the information that you requested regarding Title IV of S. 341.

Although A.I.D. will not be testifying before your Committee today, we will be submitting testimony for the record on our activities in renewable energy and energy efficiency. Additionally, A.I.D. would be happy to answer any questions for the record, or meet with your staff regarding any further information you might request on this issue.

Sincerely,

Ray Randlett

R. Ray Randlett
Assistant Administrator
for Legislative Affairs

STATEMENT OF

RICHARD E. BISSELL
ASSISTANT ADMINISTRATOR
BUREAU FOR SCIENCE AND TECHNOLOGY
AGENCY FOR INTERNATIONAL DEVELOPMENT

SUBMITTED TO THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
March 21, 1991

A.I.D. appreciates the opportunity to submit testimony to this committee on the subject of the export of renewable energy and energy efficiency technology. U.S. renewable energy and energy efficiency products and services can make important contributions to meeting the energy needs of developing countries in an economic and environmentally sustainable manner. A.I.D. has been a member of the Committee on Renewable Energy Commerce and Trade (CORECT) since that committee's inception. The Agency is pleased to state its positive judgement of CORECT and to briefly review for the Senate the reasons for that endorsement and the Agency's recent supportive activities.

A.I.D. Support for CORECT

A.I.D. believes that CORECT, under the leadership of the Department of Energy, has played a useful role in increasing the communication among federal agencies on the subject of renewable energy and more recently on the subject of efficiency. Both of these themes are extremely important elements in any effective strategy to deal in the long term with the economic and environmental problems of energy sector development in developing countries. And these needs in the developing world coincide with exciting export opportunities for U.S. industry. The U.S. produces many state-of-the-art technologies relevant to these themes. The existence of CORECT as an inter-agency commission gives the federal government an opportunity to design coherent and synergistic programs that simultaneously meet the development goals of A.I.D. and the commercial goals of the Department of Commerce, OPIC, and Exim Bank, while using the technological expertise of the Department of Energy and the Environmental Protection Agency. Working together, we can assist the U.S. renewable energy and energy efficiency industries in establishing commercial beach heads and sustainable markets internationally.

A.I.D., through charter, mandate, and action, has taken a leadership role in supporting innovative programs to promote energy efficiency and renewable energy applications in A.I.D.-assisted countries. By working closely with the World Bank and the other multilateral development banks, and with host country government agencies and development banks, A.I.D. has launched several major projects that are serving a pathfinding role in the process of international development. For example, the Energy Management Consultation and Training (EMCAT) project in India provides $20 million of A.I.D. grant funds that are leveraging $500 million in World Bank and Asian Development Bank funds and $500 million local currency from the Government of India. EMCAT will promote widespread use of energy-efficient technology in India's electric power sector. The Project to Accelerate Commercial Energy Research (PACER) is another A.I.D.-designed program in India that provides both hard currency and local currency support for new commercial initiatives (both indigenous and U.S./Indian joint venture) in such areas as renewable energy, energy efficiency, clean coal technology, and improved technical and financial management of Indian electric utility companies.

The Environment and Energy Components of A.I.D.'s Business and Development Initiative

A.I.D.'s new Business and Development Initiative is expected to contain a major component that would address energy and environmental aspects of international trade and development. Under this new A.I.D. initiative, the Agency is developing a series of programs addressed at accelerating the transfer of U.S. energy and environmental products, services, and technologies to developing countries. These programs will be implemented collaboratively within the Agency, and will involve other federal agencies and international institutions. The programs will also support a public/private partnership with U.S. industry and NGOs, with appropriate cost-sharing by U.S. industry.

Implementation is expected to focus on four categories of activity: identification of business and project opportunities, venture promotion, innovative financing, and policy reform. Proposed activities are being formulated jointly by A.I.D.'s Bureau for Science & Technology and the Bureau for Asia and Private Enterprise.

The Need for Innovative Approaches to Addressing Developing Country Energy Needs

Rapid economic growth in much of the developing world is requiring even more rapid expansion of the energy and electric power sectors. The extraordinary dimensions of this expansion and its resource requirements have been discussed in a 1988 A.I.D. report to Congress entitled Power Shortages in Developing Countries: Magnitude, Impacts, Solutions, and the Role of the Private Sector. Because of limitations in the availability of capital for expansion of the electric power sector, high rates of growth in electricity demand (10 - 15% per year in some countries) cannot be met solely through conventional approaches to expansion of generating capacity. The environmental impacts of conventional large-scale fossil fuel and hydropower generation technologies are also beginning to limit the use and increase the costs of these options.

Innovative approaches incorporating energy efficiency and renewable energy technology, environmental control technology, and energy and environmental policy changes will be required to provide environmentally sustainable growth in electricity services. In many cases a dramatic expansion in the role of the developing country private sector will be necessary to provide the capital and expertise to build and operate much of the required power generation facilities and energy services. In this regard, experience in developing countries indicates that private sector generation of electricity is likely to be more efficient than public sector utilities, and often increases the use of indigenous renewable energy resources.

The Need for Multi-Agency Support to the U.S. Renewable Energy and Energy Efficiency Industries

The United States is among the world leaders in the fields of energy efficiency and renewable energy technologies, and in many cases has the most reliable and cost-effective products. In renewables this is especially true for wind energy -- both small and large (utility-scale) wind turbines, solar thermal electric power generation systems, integrated photovoltaic products and systems, advanced geothermal conversion, and biomass-based power generation and cogeneration.

However, this technological and economic leadership has not translated into significant international markets. Other countries are providing major financial assistance to their renewable energy industries to underwrite commercial beach-heads in countries where the potential commercial market for renewable energy applications is extremely large. The U.S. is engaged in negotiations within the

OECD to further restrict such financial assistance, and we will continue to use all available U.S. programs to combat these practices.

A.I.D. Activities

A.I.D. is rapidly expanding its activities in addressing energy and environmental issues in the developing world, with special emphasis in the energy area on increased use of energy efficiency and renewable energy technology, and on least-cost energy and environmental planning. In the foreign assistance authorizations and appropriations acts, the Congress mandated A.I.D. to expand existing efforts and initiate new efforts in these areas, focussing efforts on "key" countries such as Indonesia, Mexico, Brazil, and India which are large contributors to the emission of greenhouse gases, contributing to the potential for climate change.

A.I.D. is working closely with CORECT, its member agencies, and the U.S. renewable energy industry through such efforts as the following:

- A.I.D. supported the participation of a renewable energy expert from a U.S. national laboratory in a CORECT-led international trade mission to Indonesia, and will support additional missions in 1991.

- Through a three-year Cooperative Agreement, A.I.D. is providing financial and technical support to the U.S. Export Council for Renewable Energy (US/ECRE) for renewable energy education and training, reverse trade missions, and renewable energy project identification and prefeasibility assessment. Funding of this Cooperative Agreement has expanded in FY 1991.

- A.I.D. is providing parallel funding and technical support to some of the trade associations that belong to US/ECRE and to individual companies who approach us, for reverse trade missions and project development.

- A.I.D. has arranged joint industry/government workshops on technology and financing for the World Bank, the Inter-American Development Bank, and other international financial institutions.

A.I.D. is supporting new institutional mechanisms to support renewable energy and energy efficiency project and business development, through joint ventures, in-country manufacturing of U.S. products, and U.S.-led project development. These mechanisms, to be discussed in other testimony at these hearings, include the Environmental Enterprises Assistance Fund (EEAF), and expansion of A.I.D.'s Biomass Energy Systems and Technology (BEST) project to encompass solar and wind technologies, and the International Fund for Renewable Energy and Efficiency (IFREE).

The Environmental Enterprises Assistance Fund (EEAF) has been established with the assistance of A.I.D. through creation of a new non-profit entity Environmental Enterprises, Inc. The Fund will provide both debt and equity financing for new ventures and projects that support sales and diffusion of U.S. renewable energy and energy efficiency business ventures and projects in developing countries. A.I.D.'s Renewable Energy Applications and Training (REAT) project is providing $700,000 (FY 1991) in startup funds and the Agency's Asia and Private Enterprise Bureau has provided a loan of $2.4 million. Environmental Enterprises expects to make its first commitments by mid-year.

The REAT project is providing $500,000 in FY 1991 funds to Winrock International (BEST project contractor) to expand the BEST project to include support of project identification, prefeasibility assessment, and preinvestment studies for wind, solar, and other renewable energy ventures and projects. Projects that appear worthy of financing can then be submitted to the EEAF (and other sources of financing) for support.

The International Fund for Renewable Energy and Efficiency (IFREE) is being established by the U.S. Export Council for Renewable Energy (US/ECRE), with assistance from A.I.D., to support renewable energy and energy efficiency projects and business initiatives that will promote the use and diffusion of U.S. energy products and services internationally. A.I.D. is committing a minimum of $500,000 directly to IFREE and is working closely with US/ECRE to identify projects and new ventures that would be suitable for IFREE funding. The Department of Energy and the Environmental Protection Agency are providing some additional assistance to IFREE, as is the Rockefeller Foundation. IFREE would benefit from substantially expanded support in FY 1992.

A.I.D. has also established a Cooperative Agreement with the World Bank. We provided $700,000 in Fiscal Year 1990 to the Bank to support the development of renewable energy and energy efficiency programs in developing countries. These grant funds are being used to leverage much larger World Bank energy and power sector loan funds to support environmentally sustainable energy efficiency and renewable energy projects. Additional funding is planned this fiscal year. A.I.D. is also working closely with the new Global Environmental Facility (GEF) established by the World Bank to stimulate GEF support for viable renewable energy projects, and to promote other environmentally sound energy activities in developing countries.

In response to any global tender issued by the World Bank or other multilateral development bank, U.S. renewable energy and energy efficiency industries are expected to be extremely competitive, both technically and economically.

The Global Energy Efficiency Initiative

In 1989 A.I.D. launched the Global Energy Efficiency Initiative (GEEI) as part of A.I.D.'s Global Climate Change Initiative. The purpose of the GEEI is to accelerate the implementation of energy efficiency projects in developing and Eastern European Countries. A Working Group, made up of U.S. leaders in the international energy development field representing industry, NGOs, national laboratories and other federal agencies is guiding the effort. The GEEI is presently enlisting the participation of other donors, both bilateral and multilateral, to develop collaborative, focussed, and expanded efforts worldwide on energy efficiency projects in the Third World. Our objectives are to establish networks among donors, lending agencies, other concerned organizations, and developing countries to promote energy efficiency, to identify bankable projects for financing, and to strengthen developing country institutions, policies, and human capacity to markedly increase the efficiency of their energy systems. This is expected to result in a strategy on energy, environmental and sustainable development for discussion and adoption at the United Nations Conference on Environment and Development in Brazil in June 1992.

CORECT Activities

In our view, CORECT has been a productive interagency effort, working closely with the U.S. renewable energy and related industries. It has catalyzed increased information exchange, new ideas, and cooperative efforts among the agencies and in concert with U.S. industry. Specific programmatic approaches supported in the legislation -- such as special feasibility study funds and loan guarantee programs -- have been initiated by member agencies of CORECT in the last couple of years.

With regard to the report mentioned in Section 4003 of the proposed legislation, we would like to note the importance of additional topics: appropriate host country policy measures; financing mechanisms and incentives; and other initiatives that can stimulate the commercial diffusion of renewable energy and energy efficiency technology. Such activities are essential, in our experience, because without suitable in-country policies, financing mechanisms, and incentives, technically proven and economically attractive renewable energy technologies will not be financeable. A.I.D. has been supporting energy and environmental policy dialogue with developing country decision makers to catalyze changes in host country regulations, laws, and policies that would result in more rational and effective energy and environmental investments; much more is needed in order to help these countries develop the policy and investment environments in which significant use of energy efficiency and renewable energy technology can be used.

As the Committee is aware, and as is summarized in this testimony, A.I.D. has long-standing programs in energy assistance. In the course of reviewing this legislation we would appreciate consideration of A.I.D.'s role.

Conclusion

In conclusion, the Agency for International Development has found its participation in the activities of CORECT beneficial. We believe CORECT's efforts have helped to enhance the export of U.S. renewable energy products and services and simultaneously contributed to environmentally sound development in the Third World.

* * *

EXECUTIVE OFFICE OF THE PRESIDENT
OFFICE OF MANAGEMENT AND BUDGET
WASHINGTON, D.C. 20503

June 15, 1990

Honorable Mark O. Hatfield
United States Senate
Washington, D.C. 20510

Dear Senator Hatfield:

The Director has asked me to respond to your letter regarding funding for renewable energy feasibility studies by the Overseas Private Investment Corporation (OPIC).

The Office of Management and Budget has not taken any action to eliminate OPIC's authority to fund environmental feasibility studies; OPIC has the discretion to fund these studies if it wishes. Although expanding OPIC's feasibility study authority in FY 1990 does not require an appropriation, it does require an increase in expenditures from OPIC's reserves, resulting in increased outlays over budget estimates.

The FY 1991 Budget proposal for OPIC includes a $200,000 increase in OPIC's spending authority for environmental activities. I suggest that OPIC should consider using these funds for renewable energy feasibility studies.

Yours sincerely,

Robert E. Howard
Associate Director for
National Security and
International Affairs